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Article

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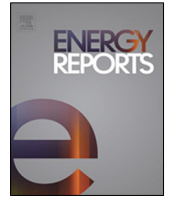
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Research paper

Electricity transmission formulations in multi-sector national planning models: An illustration using the KAPSARC energy model



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HIGHLIGHTS

- Compared to transshipment, optimal power flow affects policy-relevant outcomes.
- PV build and marginal cost of electricity delivery change with optimal power flow.
- A single node in each region for power flow maintains model tractability.
- A version of optimal power flow with transmission losses shows limited effect.
- Domestic market-clearing price of natural gas varies slightly across model versions.

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ABSTRACT

The purpose of this study is to assess the policy-relevant effects of incorporating a more proper representation of electricity transmission in multi-sector national policy models. This goal is achieved by employing the KAPSARC Energy Model (KEM), which is the first publicly available large-scale energy policy model for Saudi Arabia. Past studies using KEM have examined industrial pricing policy, residential energy efficiency, the prospects of power generation technologies, and residential electricity pricing. These studies have shown that under certain fuel pricing scenarios, significant renewable energy capacity is deployed. With large-scale renewable technologies introduced in the power system, representing transmission more appropriately becomes important. By incorporating a direct current optimal flow model, our results show

- the optimal investment in utility-scale photovoltaics are 30 percent lower, and the weighted average marginal costs of delivering electricity are 100 percent higher, compared to a model that has a transshipment formulation,
- a version of KEM with a single node in each region for transmission and without transmission losses provides valuable insight while keeping the model size tractable,
- the market-clearing price of natural gas in a deregulated environment modifies slightly, demonstrating that a transmission component predominantly affects the operations of the power system. Although the scarcity of natural gas increases slightly due to lower PV deployment, its greater use by power generators is minor.

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1. Introduction

Large-scale national energy systems models, which date back to the 1970s, have been developed with different levels of detail to examine the effects of policy scenarios (Hall and Buckley, 2016; DeCarolis et al., 2017). The aim of these models is to aid decision makers in formulating energy policies. Modelers must exercise

trade-offs in which sectors are represented, and to what extent, to make the models tractable and relatively easy to use.

Electricity is considered a cornerstone for economic, social, and industrial activity in any country. Hence, the power sector, which comprises generation and transmission segments, receives particular attention during the development phase of any national policy model. However, in order to maintain model tractability and to keep solution times within a reasonable limit, the power transmission segment is not generally described with the same level of detail as the power generation segment. The latter is true for most multi-sector national energy systems models, including

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the National Energy Modeling System (NEMS) of the Energy Information Administration (EIA) and the International Energy Agency's (IEA) TIMES (short for The Integrated MARKAL-EFOM System).

Typically, when modeling transmission, a transshipment formulation (i.e., a transportation model) has been adopted. In this type of formulation, the electron movement does not adhere to Kirchhoff's Current and Voltage Laws.¹ Rather, electricity flows similar to fuel transport in pipelines. The popularity of this method stems mainly from the fact that it is easy to model, and can suffice for a certain type policy questions. However, other policy studies may require a more detailed description of the power sector. For example, as penetration rates of renewable technologies continue to rise in power systems, network congestion concerns become more pronounced (Yang et al., 2012), and a better representation is to be used to capture these, and other, operational facets.

Taking Kirchhoff's Laws into account in a transmission model would consider two key features of power flows; the flows cannot be controlled, although some devices allow for partial control, and power travels over all paths between generators and load points. To this end, it has been reported by Krishnan et al. (2016) that models that rely on a transshipment method in place of a proper transmission model generally underestimate additional transmission capacity requirements. This has major budget implications as the capital requirements for the transmission sector are immense (Rosellón, 2003).

Another aspect to consider when analyzing transmission problems is the strong interdependence between transmission and power generation investments. Traditionally, transmission planning followed whatever plans were set for generation builds. But the advent of renewable generation has identified deficiencies in this practice (i.e. transmission follows generation) (Spyrou et al., 2017). Ignoring the highly interwoven nature of generation and transmission will result in increasing capital and operational costs (Spyrou et al., 2017; Roh et al., 2007).

Based on the above, the objective of this paper is to assess the extent to which introducing a more detailed transmission description in a national energy system planning model would affect decisions made by the included sectors. This objective is sought within the context of the KAPSARC Energy Model (KEM), which is a multi-sector energy model that describes several energy-intense sectors in the Saudi economy.

KEM currently comprises seven energy sectors, like oil refining and power generation, but it does not have a proper electricity transmission representation. Similar to other models of its type, it adopts a transshipment formulation. We include a direct current optimal power flow (DCOPF) formulation in KEM with and without transmission losses; the DCOPF problem is also estimated using a single node and three nodes per region. We then compare output from all versions of the model using two fuel pricing policy scenarios: 2015 regulation and deregulation of fuels. The effect on investment decisions made by the power generation sector, and the cost of delivering electricity are of particular interest.

There are two areas where we think the addition of a DCOPF component can directly influence policy assessments. Firstly, a more detailed description of power transmission may impact power generation investments (Krishnan et al., 2016). Recently, Saudi Arabia has announced a target of 9.5 GW of renewable electricity to be installed by 2023, and even more could come later on. Further, the electricity sector will also undergo several regulatory changes which have been found to directly impact transmission

planning activities (Munoz et al., 2014). Whereas the model could integrate large quantities of variable renewable technologies if fuel prices were sufficiently high, incorporating a more detailed representation of the transmission sector will be vital in quantifying congestion, and in identifying physical limitations of the grid (van der Weijde and Hobbs, 2012).

Secondly, the marginal cost of delivering electricity is expected to change, and if these changes are carried over to the customer then the demand for electricity will also change. In addition, there may be tertiary effects that have wider ramifications on the economy. Within the Saudi context, for example, we note that the demand for domestically-sourced natural gas is currently higher than its supply due to its low price set by the Saudi government – Saudi Arabia does not trade natural gas.

This paper is structured as follows: the next section provides a review of studies that have previously explored this topic and current multi-sector models. We then describe the approach undertaken to answer the research question. We conclude the body of the paper by displaying and discussing the results.

2. A review of electricity transmission representation in national multi-sector energy models

Studies that have explored the policy relevance of adding a DCOPF component to multi-sector national planning models are limited. Lehtila and Giannakidis (2013) highlighted the importance of having a proper transmission model in the case of high deployment of intermittent renewable power generation, where their application of a transmission model was in the context of TIMES. Essentially, congestion is a product of several factors, such as the hourly demand profile and changes in the costs of electricity transfer. In the case of intermittent renewables, their output spike at a given time segment means a sudden increase in supply takes place at a very low cost to the generators; this will impact the source from which the electricity is obtained as well as the cost of its delivery.

On the other hand, PLEXOS is a configurable integrated model with multiple sectors represented, including the natural gas network, the power system, and water desalination. The model can be used for policy assessments at the national level, and contains an optimal power flow formulation. Many policy studies have used the transmission features of PLEXOS (e.g., Moazzen et al., 2016; Garrigle et al., 2013). Furthering the modeling arguments of Lehtila and Giannakidis (2013), Moazzen et al. (2016) used PLEXOS in their analysis specifically because large-scale integration of renewables warrants a proper representation of the transmission grid. Deane et al. (2013) also complemented their TIMES analysis with PLEXOS, specifically to overcome the approximations made in an energy system model. Although they cited the coarse temporal resolution adopted in TIMES as a reason for using PLEXOS, the transmission component was a key element in their pursuit for “technical appropriateness” of the results. Table 1 summarizes the power generation and transmission characteristics of a few multi-sector national models in use today.

Furthermore, the Long-range Energy Alternatives Planning (LEAP) system has been used extensively in country-level energy policy analyses (e.g., Emodi et al., 2017; Gusano-García et al., 2018). Electricity generation expansion modeling in LEAP may be augmented to use the Open Source Energy Modeling System (OS-eMOSYS) (Stockholm Environment Institute, 2011). As Howells et al. (2011) describe, OS-eMOSYS adopts an optimization approach to the generation system, but the model does not have a formulation for electricity transfer between regions. The lack of transmission formulation in OS-eMOSYS is further validated by Dhakouani et al. (2017).

While not in the context of planning models that span multiple sectors, Krishnan et al. (2016) performed a review of combined

¹ Kirchhoff's Current Law states that incoming and outgoing electricity current at a junction must sum to zero. Kirchhoff's Voltage Law ensures that the sum of all potential differences around a closed loop is equal to zero. They inform proper electricity transmission modeling, and power transfer distribution factors can be computed as an extension of such modeling to show the impact of incremental power flow in the transmission system.

Table 1
Characteristics of multi-sector national planning models when it comes to representing power systems.

	Overall approach	Regional scale	Electricity flow after generation
NEMS (EIA, 2017)	Optimization	The contiguous United States, broken up into 22 regions	Transshipment
TIMES (Loulou et al., 2005; IEA, 2018)	Optimization	For generic use (for any particular region or country)	Transshipment
KEM before transmission addition; (KAPSARC, 2016)	Equilibrium	Saudi Arabia, broken up into four regions	Transshipment
PLEXOS (Energy-Exemplar, 2017)	Optimization (commercial software taking an integrated view natural gas networks, power, and water desalination)	For generic use (for any particular systems, regions, or countries)	Optimal flow formulation (with flexibility in the number of transmission nodes)
LEAP (Stockholm Environment Institute, 2011)	Accounting framework; electricity sector may be based on OSeMOSYS, which adopts an optimization approach.	For generic use (for any particular region or country)	OSeMOSYS does not model inter-regional electricity flows

generation and transmission expansion models and their impact on policy assessments. They show and discuss that a model combining both produces lower power system costs than either one alone, and that investment decisions are affected. They showed that optimization of both components yield differing investment decisions than those of a generation-only model. Their paper supported the idea of studying the effects of a more rigorous transmission formulation in multi-sector models. In the same context, Ahmed et al. (2017) applied a combined generation and transmission modeling framework to assess the trading of electricity between the member countries of in the Association of Southeast Asian Nations. They used one to three transmission nodes for each member country.

Additionally, the Regional Energy Deployment System (ReEDS) is a model of the US electricity system that is maintained by the National Renewable Energy Laboratory (Short et al., 2011). It has the option to either run with a transshipment or an optimal power flow formulation; modelers of the ReEDS thought it was worthwhile to include a more accurate transmission representation. Bloom et al. (2016) jointly used ReEDS and PLEXOS to assess the deployment of wind and photovoltaics (PV) in the US' Eastern Interconnection. The balancing of the transmission system was important in this context. Generally, however, national planning tools require low spatial and temporal resolutions to be able populate them with data and solve them within a reasonable timeframe.

3. Approach and methodology

KEM already had seven integrated sectors, with their operation represented in four regions of Saudi Arabia; the model is described by KAPSARC (2016). That version consisted of the electric power, petrochemicals and fertilizers, oil refining, water desalination, oil and gas upstream, and cement sectors. There have also been instances where a separate bottom-up model has been used to represent the electricity loads of the residential sector. The model was designed as a mixed complementarity problem (MCP) to make it easier to represent an economic system in which the prices of goods exchanged between sectors deviate from those in competitive environments. Each sector is contained within its own sub-model, and acts as an agent that makes decisions on fuel use, investment, and operation to minimize its cost or maximize profit. Those decisions are based on a set of physical and economic constraints that characterize each sector's operation. The sub-models are integrated to find an equilibrium state. Having multiple sectors is vital in this case because all consumers of natural gas compete over a scarce domestic supply, and Saudi Arabia has a policy where no primary fuels are imported.

The formulation of the electric power demand in KEM consists of 24 representative chronological load curves; one for each of the three seasonal periods, two day types, and the four regions.



Fig. 1. Distribution of transmission nodes in each of the four regions in KEM.
Source: KAPSARC.

Each load curve is discretized by eight load segments with varying number of hours in each one. We have tried finer discretization schemes, but ultimately, model tractability was a priority.

Renewable technologies in KEM are characterized by their capital costs, operation and maintenance (O&M) costs, and diurnal resource profiles. Their operation further imposes cost on thermal generators as a result of maintaining a higher level of operating reserves to back up their generation, and additional ramping brought upon by the nature of their – intermittent – resource profiles. Concentrating solar power (CSP) plants have the benefit of operating thermal energy storage, which would lessen these additional system costs; however, CSP may not appear in the solution due to its high investment cost in 2015.

Currently, KEM has a transshipment formulation, which does not adhere to physical constraints that govern the transfer of electricity, like Kirchhoff's laws. This is critical to point out because we examine policy scenarios that bring about large amounts of renewable generation in the mix. Thus, we have added an eighth sector for the transmission of electricity. Two regional disaggregation schemes are used to assess the contribution of transmission: one and three nodes per region.

The regional and nodal breakdowns used in the model are displayed in Fig. 1 for the latter case; this is an approximation as multiple lines may connect two of the regions presented. For the single-node case, physical laws are still satisfied for interregional transmission, assuming one line existing between any of the two

regions. Light gray nodes represent inter-regional connections, while those in dark gray show those for intra-regional transfer. Furthermore, the solid lines are existing transmission lines, while the dashed lines are ones that are not built, but the model allows for their construction. Transmission lines are modeled only within the country for the purpose of KEM, although price-based trading with the rest of gulf cooperation council (GCC) countries and Egypt is planned in the future.

Fig. 2 illustrates how transmission is integrated with other sectors in KEM. The transmission system operator (TSO) is treated as a separate entity from the generation sector. In the model, any generated electricity is sent to the TSO, and power loads – whether exogenous or endogenous – are satisfied in the electricity transmission sub-model. The solid arrows between the sectors show the flows of physical goods. For example, the arrow heading to cement production from electricity transmission indicates that electricity is sent to the cement sector.

An alternating current optimal power flow (ACOPF) problem properly models the physical phenomena that govern electricity transmission (see Eldridge et al., 2017). Due to its computational complexity, however, most researchers prefer a DCOPF representation as it is a linear approximation of the problem (e.g., Lehtila and Giannakidis, 2013; Hedman et al., 2009); therefore, it is used in this analysis. The set of equations and constraints in Appendix A define the implementation of the DCOPF problem used in KEM. Our model is similar to that of Hedman et al. (2009), but it is instead formulated as a continuous problem, to retain its suitability for linkage with KEM; dual variables of discrete equations lose their economic sensibility.

The objective of the problem is to minimize the total cost of the transmission system. This includes any investment, fixed and variable O&M costs, and electricity purchased from the generators. We do not minimize the cost for the entire power system (i.e., generation and transmission).² Rather, we have an (implicit) objective function for each sector independently within the MCP framework. We did this because the local TSO is in the process of decoupling from generation operations. At the present state in Saudi Arabia, the grid is controlled by the major utility, which also is in charge of most generation capacity. The transmission cost is just being added to the generation costs, without the generators necessarily modifying their operations that achieve least-cost for them. The electricity is traded at marginal cost of supply between generators and TSOs. The transmission component is linked with the rest of KEM in two areas; the objective function has the electricity supply variable from the generation side, and the demands for electricity from other sectors and the wider economy feed into the last equation in Appendix A.

Since DCOPF models typically exclude losses, we test a case where transmission losses are included. Hobbs et al. (2008) show a slight impact of losses on the nodal prices, but we do it to see their effect on other metrics, like investment decisions, and for the sake of completeness. We have added a losses component as presented by Fitiwi et al. (2016). The simplest formulation in that paper would be linear if we assume no investment in transmission capacity is made; however, because the goal of this model is to also serve for multi-period expansion, the equation represented has non-linear terms. This is shown below by Eq. (1) in stylized form, and Equations A6 and A7 in Appendix A for the implementation in KEM. $L_{h,n,nn}$ are the line losses in each time segment in the day (h), from the supply node, n , to the receiving node, nn . They are a function of line resistance ($r_{n,nn}$ in per-unit terms), divided by the base power (P_{base}) to have effective resistance in ohms, the maximum power that could be transmitted by the line ($C_{n,nn}$), and

the bi-directional flow of power ($T_{h,n,nn}$ and $T_{h,nn,n}$). $C_{n,nn}$, in KEM, would include both existing and built line capacities. We expect longer computation time as a result. Piecewise-linear formulations are more accurate, as presented by Fitiwi et al. (2016), but are attained at a dramatically larger model size.

$$L_{h,n,nn} = \frac{r_{n,nn}C_{n,nn}}{P_{base}} (T_{h,n,nn} + T_{h,nn,n} - 0.165C_{n,nn}) \quad (1)$$

KEM is run in a long-run, steady-state year for the purpose of this paper. This means we take the capital costs for investment annualized over the designed lifetimes of the assets, and consider that the power sector is able to make investment decisions by taking a long-run view.

The model is calibrated to the year 2015. Most of the data inputs are described by Matar and Anwer (2017); the input data for the generation side are highlighted in Appendix B. Other facets of the data that pertain to the representation of the TSO were, however, needed for this version of the model. Investment costs for transmission lines are obtained from the Energy Technology Systems Analysis Programme (2014), and inter-regional transmission capacities are acquired from correspondence with the Electricity and Co-generation Regulatory Authority (ECRA), the Saudi power regulator. There are no accessible data for the intra-regional capacities, so we set them to be higher than any of the regional demand in the system. This is a rough assumption; however, as it means that we place emphasis on congestion in the lines between the regions.

We only have hourly power demand curves for each of the four regions. For the three nodes per region case, we used population distributions available from the General Authority of Statistics (2017) to distribute the load demands to each node. Moreover, we used the existing generators' geographical proximity from ECRA's National Electricity Registry (2017) to assign them to each of the three nodes. For the single-node case, the demands and generators per region are the same as were used in KEM before. For new investments, we specify that nuclear plants may be built only in the nodes closest to the coasts; this is because of water accessibility at those nodes. New renewable or fossil-fueled power generation capacity is distributed evenly along regions' nodes.

The resistance values for transmission lines are estimated by using aluminum alloy's resistivity multiplied by the lines' distance divided by their cross-sectional area; the number of conductor strands and their diameters vary depending on voltage class. Typical susceptance values are shown by Lowe (2015), but the units of both metrics were converted to a per-unit system. We also impose lower and upper limits of the nodal voltage phase angles of ± 0.6 rad, as mentioned by Hedman et al. (2009).

The analysis is performed for two fuel pricing cases, while everything else remains constant, including the electricity price that consumers would encounter and therefore their demand. The first is the 2015 fuels regulation scenario, where the utilities and industry will face the regulated fuel prices and natural gas supply quotas in 2015. For instance, the regulated fuel prices were 4.24 \$ per barrel for crude oil, and 0.75 \$ per MMBTU for gas in 2015. The second is called 2015 fuels deregulation in which crude oil and refined oil product prices will be set to their 2015 international market prices, and natural gas will be set to its domestic market-clearing price. The market-clearing price of gas is determined by the model. For more information on Saudi industrial fuel prices, see Matar et al. (2016, 2017). Results for three cases will be discussed:

1. KEM without a transmission component: transmission in this case is replaced with a transshipment formulation,
2. KEM with a DCOPF component, but without losses, and
3. KEM with a DCOPF component and losses.

² While the TSO minimizes its own cost in our model, total generation and transmission costs would be minimized in a purely competitive market.

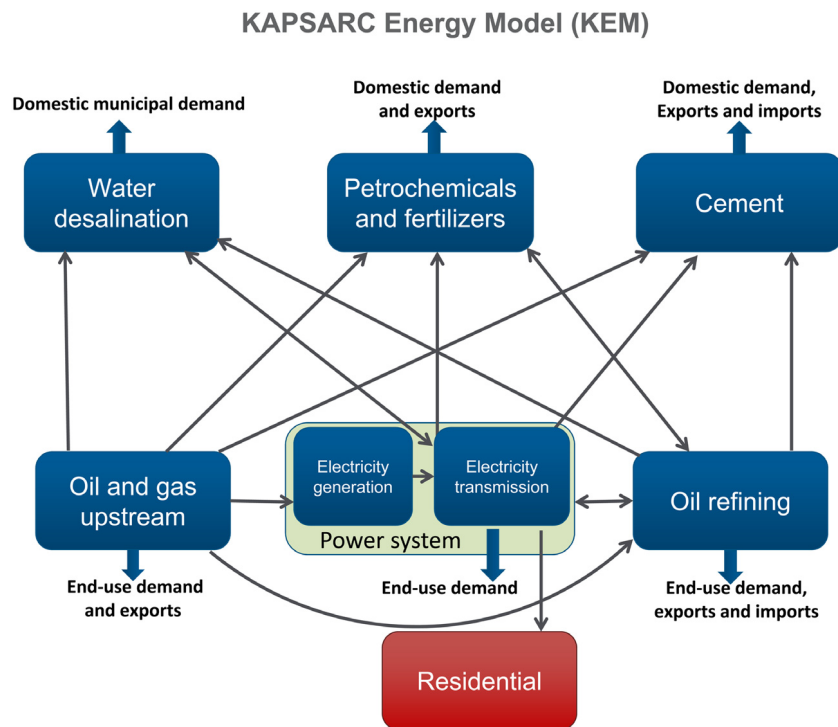


Fig. 2. Sectors modeled in this version of KEM.
Source: KAPSARC.

4. Results and discussion

In this section, we explore the effects of a more proper transmission component on investment decisions, cost of delivering electricity, the total power system cost, and the deregulated price of natural gas at which various consuming sectors would make their purchase. These metrics are relevant to national policy assessments. Additionally, versions of KEM with and without losses are tested not only for the same results, but also compared against the other versions in the time it takes to converge. We will first explore the case of three nodes per region.

Generation investment decisions are a key metric to judge the effects of having a proper transmission formulation on policy assessments. As shown in Fig. 3, there is a clear difference between a version of KEM with and without the DCOPF component when renewable technology is added.

When fuel prices are fixed at their 2015 levels and natural gas supply quotas for each sector are imposed, we observe a slight increase in the combined-cycle gas turbine (CCGT) capacity that is built. Investments when fuel prices are set to their 2015 levels are expected to be minimal because we calibrate to that year. New builds mostly arise from the reserve margin requirement that we impose. Saudi Arabia did not independently meet the requirement in 2015 as it had reserve margin sharing through the interconnection between GCC member countries.

When fuels are deregulated in 2015, we see that significant investments are made in CCGT to raise the thermal efficiency of generators and use less fuel. Given the overall supply constraint of natural gas, and the fact oil is more costly as a result of deregulation, the remaining electricity demand is met by PV plants (see Matar et al., 2016, 2017). We observe a reduction of over ten GW of PV with a DCOPF component included, compared with the results of a transshipment formulation. The decline in PV deployment results in more conversion of open-cycle gas turbines to CCGT,³ and

the higher use of natural gas. In a deregulated fuels setting, KEM with transshipment finds an equilibrium state when the power generators use 1.6 quadrillion BTU. A version of the model with DCOPF without losses finds their use would be 1.8 quadrillion BTU.

Based on a full PV capital cost of 1436 dollars per kW in 2015, that is nearly 20 billion dollars in less expenditure in the long-run. To get an idea of the size of the domestic sector, the operating revenue of the local power utility, the [Saudi Electricity Company \(SEC\)](#) (2016), was around 11 billion dollars in 2015; this company is in charge of both generation and the grid.

The lower PV deployment is a result of the operability of the transmission system. With previous versions of KEM, the power system could supply electricity demand at will. If a region exhibited 1 GW of power load, then it could be supplied the 1 GW directly from any plant. Whereas with this version, if one region has a 1 GW load, the supply region has to keep in mind that power has to flow along all transmission lines, and has no full control to divert it all to the demand point. This causes a different equilibrium of supply and demand compared to previous versions.

There is little difference in the level of national investments made in a model that has a DC load flow formulation with losses and one that does not have losses. Table 2 further shows that regional PV installations are similar when comparing models that have a DC load flow component; however, investments in CCGT are altered in the central and eastern regions of Saudi Arabia.

In a case where oil prices are raised to international prices in 2015, Table 3 highlights the average long-run marginal cost (called *marginal cost* from here on) of electricity delivery, weighted by quantity supplied to that region or node. This value is determined by the dual variable associated with the demand constraint, which is defined by Equation A10 in Appendix A. In the versions of KEM that have a DCOPF representation, this equates to the locational marginal price (LMP). The LMP factors in the congestion along a particular transmission line in particular time of the day. For the same scenario, Figs. 4 and 5 additionally illustrate this metric for an average summer weekday in the central and western regions,

³ KEM has the ability to upgrade a portion of the existing open-cycle gas turbines to CCGT plants. The resulting CCGT plants are slightly less energy efficient compared to newly installed CCGTs.

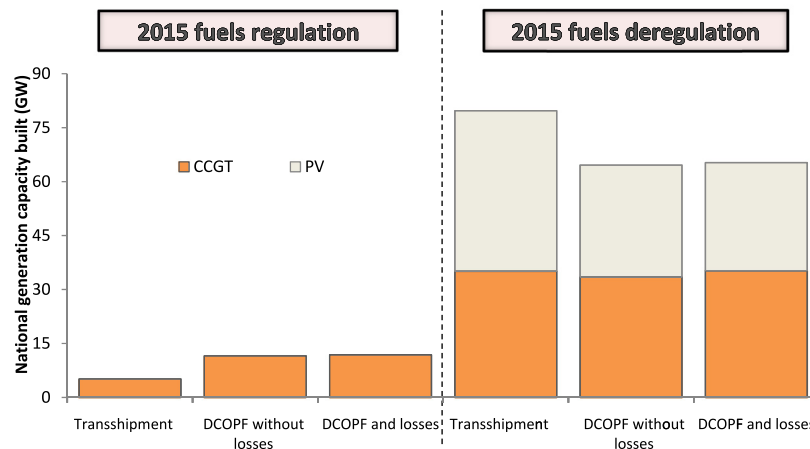


Fig. 3. Generation capacity that is built using KEM in the fuel pricing scenarios with and without a DCOPF component.

Table 2

Generation capacity built in each region in the 2015 fuels deregulation scenario (units in GW).

Region in Saudi Arabia	Technology	2015 fuels deregulation		
		Transshipment	DCOPF without losses	DCOPF and losses
Southern	CCGT	3.5	3.1	3.5
	PV	17.4	3.6	4.0
Western	CCGT	9.2	4.7	5.5
	PV	0.7	4.5	4.4
Central	CCGT	4.4	5.5	10.9
	PV	26.5	17.0	17.4
Eastern	CCGT	18.0	20.1	15.3
	PV	0	6.1	4.3

Table 3

Marginal cost of delivering electricity, total power system costs, and the market-clearing price of natural gas in 2015 fuels deregulation, with and without a DCOPF component.

	KEM with transshipment	KEM with DCOPF without losses	KEM with DCOPF and losses
Average marginal cost of delivering electricity (\$/MWh)	72.62	143.15	156.97
Total power system costs (Billion \$)	26.25	39.83	40.66
Deregulated price of natural gas that the utilities and other sectors pay ^a (\$/MMBTU)	8.57	8.59	8.76

^a For comparison, the regulated natural gas price was 0.75 \$/MMBTU in 2015.

respectively. The regions are single entities in KEM without the DCOPF component, and as Fig. 1 shows, nodes 4, 5, and 6 comprise the western region, and nodes 7, 8, and 9 constitute the central area.

The results show that the marginal generation cost is similar⁴ between the different versions of KEM, even when we test a single node per region, as described in the following section. On average, however, the marginal cost of delivery to the customers nearly doubles compared to a version of KEM that uses a transshipment model. That could have large demand response effects if this cost influences the price for consumers. While a transshipment model assumes trade of electricity between two regions does not affect the load flows elsewhere, and that it can be done at will, a DC load flow model considers electricity trade between two regions would affect the entire network. If the model does decide to trade, it also has to consider the power flow that would not make it to the

demand region. So the marginal cost of transmission would rise. Moreover, the effect of incorporating transmission losses is limited on this metric as well compared to the transshipment case.

Figs. 4 and 5 also show there is a surge in the LMPs of the evening and early nighttime periods in node 6 that is exacerbated by including losses; the surge is more substantial in the western region. In the west, for example, a combined 0.159 TWh is transmitted from 7 pm to 9 pm on a summer weekday from nodes 4 and 5 to 6. It is clear the demand at node 6 is higher than the generation capacity at that location. Additionally, the operation of significant levels of PV requires dispatchable capacity to ramp up considerably around dusk. The onset of PV is also the reason behind the declining marginal costs in the middle of the day.

Also, we see a large change in the aggregate power system cost with DCOPF in place. In the original version of KEM and the version with a single-node-per-region DCOPF model, despite the vast area covered by a single region, intra-regional transfer of electricity is characterized by a single value of distance, and thus one variable O&M cost parameter. In the 3-nodes-per-region DCOPF version, we

⁴ The marginal generation costs during the daytime are lower for a model with transshipment due to the higher penetration of PV.

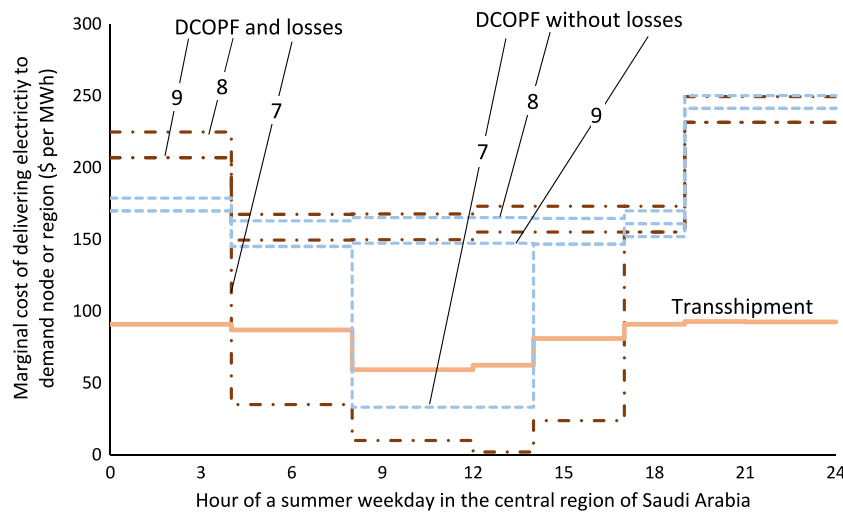


Fig. 4. Marginal cost of electricity delivery in 2015 fuels deregulation with and without a DCOPF component in the central region on a summer weekday.

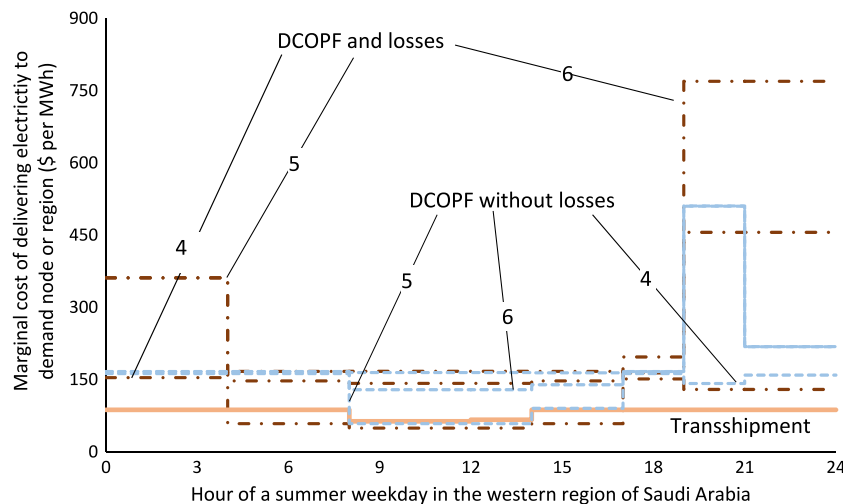


Fig. 5. Marginal cost of electricity delivery in 2015 fuels deregulation with and without a DCOPF transmission component in the western region on a summer weekday.

alternatively have three line distances in each region. That single distance value is lower than the sum of the line distances in the three-node-per-region case. As a result, we observe significantly higher system costs.

We looked at the domestic market-clearing price of natural gas, as well, to examine the wider economic impacts of adding in a DC load flow formulation. The price would be relatively stable, especially considering the model would have a “simplification” error compared to reality. We had thought if having a DCOPF component would affect the fuel use decisions made by the generators, its effects may permeate the rest of the economy as the gas supply constraint improves or worsens. In this respect, generators shift to using more natural gas as a fuel in the 2015 fuels deregulation case, but that rise translates to a lower increase for the natural gas price. The higher use indicates that other sectors consumed less natural gas, as the total gas produced in 2015 is held constant.

4.1. KEM with a more proper transmission formulation and a single node in each region

To test the effect of having more extensive regional disaggregation versus just a DCOPF model, we carry out the analysis of a model with a strict transmission component but with a single node

per region; so four nodes in total to represent the four regions we had in previous versions of KEM.

Shown in Table 4, there are some differences in the marginal cost of electricity delivery, but certainly starker in the power flow versus transshipment cases. The investments in PV capacity with DCOPF and one node per region remain in line with the three-node-per-region representation. This is shown by the level of – annualized – investments in the table. The market-clearing prices of natural gas are similar in all cases.

The cost of the power system in meeting demand, as discussed earlier, is clearly influenced by the regional disaggregation. A finer geographical topology results in higher operating costs within the grid than a simplification of the regions.

4.2. Comparison of computational performance across different versions of the model

Since KEM is a large MCP, and the solver we use, PATH 4.7.02, is not as mature as existing linear programming solvers, scaling of the variables and equations is critical to achieve convergence within a reasonable timeframe. The solution run-times for the model are recorded in Table 5 after testing of different scaling procedures. The processor is an Intel Core i7-5600U clocked at 2.60 GHz with 8 GB of memory, and we use a 64-bit operating system.

Table 4

Comparison of the results in Table 3 with three nodes and one node per region.

		KEM with transshipment	KEM with DCOPF without losses		KEM with DCOPF and losses	
Number of nodes per region →		N/A	3	1	3	1
Average marginal cost of delivering electricity (\$/MWh)	2015 fuels regulation	15.75	45.73	27.31	54.77	31.09
	2015 fuels deregulation	72.62	143.15	155.28	156.97	136.37
Total power system costs (Billion \$)	2015 fuels regulation	5.58	19.43	6.69	19.48	6.74
	2015 fuels deregulation	26.25	39.83	27.43	40.66	27.07
Deregulated price of natural gas that the utilities and other sectors pay (\$/MMBTU)	2015 fuels deregulation	8.57	8.59	8.59	8.76	8.38
Annualized investment cost in PV ^a (Billion \$)	2015 fuels deregulation	4.73	3.30	3.15	3.18	3.23

^a Estimating the full capital cost of utility-scale PV in 2015 as 1436 \$/kW, discounted at 6 percent over 25 years.**Table 5**

Model size and solution times in each version of the model.

		KEM with transshipment	KEM with DCOPF without losses		KEM with DCOPF and losses	
Number of nodes per region →		N/A	3	1	3	1
Number of variables in a single-year simulation	2015 fuels regulation	53,234	60,867	54,207	67,395	56,127
	2015 fuels deregulation	53,210	60,843	54,183	67,371	56,103
Solution run-time (s)	2015 fuels regulation	46	110	44	154	44
	2015 fuels deregulation	48	113	53	289	53

There is significant deviation in the results going from a transshipment formulation to a DCOPF representation. The difference in marginal costs of delivery, power system costs, and investments would have an impact on policy assessments conducted with KEM. Furthermore, given that extra nodes do not alter the investment decisions and the LMPs significantly, we propose to use KEM with DCOPF and a single node per region, but either with or without losses. As can be seen, the change in the solution run-time and the number of variables with such model specifications are manageable; however, if KEM were to be expanded with additional technologies or sector representations in the future, the user may place emphasis on the model size and prefer a lossless model. The time it takes the model to solve becomes pertinent when running it in multi-period form, where it can take up to 36 h to solve.

5. Conclusion

The contribution of this paper is to show the impact of including a more proper electricity transmission element in a multi-sector national planning model. Most of these types of models rely on transshipment formulations instead. Yet, recent literature has stressed the fact that having transmission constraints is necessary for renewable power generation deployment.

KEM is one multi-sector planning model that applied a transshipment formulation in previous analyses. To test the effects of a different transmission formulation, we augmented KEM with DCOPF component with and without transmission losses; the DCOPF problem was additionally estimated using a single node and three nodes per region. We then compared output from all versions of the model using two fuel pricing policy options. We particularly looked at the investment decisions by the power generation sector, the long-run marginal cost of delivering electricity, the cost to the power system as a whole, and the market-clearing price of natural gas in a deregulated setting. These are some metrics that are relevant when generating policy assessments.

We found substantial differences in the average marginal cost of electricity delivery and the investment costs between KEM with

a DCOPF formulation versus transshipment. The optimal investment in utility-scale photovoltaics are 30 percent lower, and the weighted average marginal costs of delivering electricity are 100 percent higher, compared to a model that has a transshipment formulation. Incorporating transmission can in fact generate about \$20 billion in avoided full investment costs in power plants in the long run. To compare this to the size of the domestic sector, the operating revenue of [Saudi Electricity Company \(SEC\) \(2016\)](#) was around 11 billion dollars in 2015.

These differences are comparatively restrained when transmission losses are added to the model. In this vein, the results showed the inclusion of simplified losses in the model does not change the convergence time. The model size does, however, rise slightly with the addition of losses.

The time required to solve the model will become relevant when we run it in multi-period fashion. Having one or three nodes per region in the DCOPF formulation yielded a large effect on the solution time, however, both versions generated similar average LMPs and PV investments for a case in which fuel prices are deregulated. The largest difference in the two versions of a proper transmission component is the power system cost. A more disaggregated view of the grid will produce higher operation costs. In this sense, the transshipment and single-node transmission versions output similar costs.

Ultimately, based on the results, we would adopt a single-node-per-region DCOPF formulation with or without losses to produce policy studies within a reasonable time frame with KEM. For model expansion, the modeler may have to keep the model size within reason and remove losses.

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Appendix A. DCOPF model formulation in KEM

The transmission sub-model is more completely described below; here we only show it as a linear program, although in KEM it is written as MCP. KAPSARC (2016) shows the model formulation of the other sectors in KEM. The nodal placements for the three-nodes-per-region version, and the lines connecting them, are shown in Fig. 1. There are three voltage classes in the version that represents three nodes per region: 132, 230, and 380 kV. Only inter-regional 380 kV lines are included in the single-node version.

Sets

```
ELp power plants /[thermal power plant technologies],PV,wind,CSP/
ELl load segments in a day /L1*L8/
ELs seasonal periods /summ,wint,spfa/
ELday types of day /wday,wendhol/
v vintage /old,new/
r regions /sout,west,cent,east/
time time period for defining parameters and tables /t1*t30/
trun(time) final model run time period /t1*t1/
t(trun) dynamic set for time
alias (r,rr);

GRn grid nodes or buses /n1*n12/
GRnr(GRn,r) grid nodes by region /(n1*n3).sout,
                                   (n4*n6).west,
                                   (n7*n9).cent,
                                   (n10*n12).east/

GRvolt grid line voltages /v380,v230,v132/
GRhvolt(GRvolt) high voltage /v380/

GRline(GRn,GRnn,GRvolt,r,rr) transmission lines /n1.(n2*n3).v132.sout.sout,
                                                    n2.n3.v132.sout.sout,
                                                    n4.(n5*n6).v380.west.west,
                                                    n5.n6.v380.west.west,
                                                    n7.(n8*n9).v132.cent.cent,
                                                    n8.n9.v132.cent.cent,
                                                    n10.(n11*n12).v230.east.east,
                                                    n11.n12.v230.east.east,
                                                    n2.n4.v380.sout.west,
                                                    n2.n8.v380.sout.cent,
                                                    n2.n10.v380.sout.east,
                                                    n4.n8.v380.west.cent,
                                                    n8.n10.v380.cent.east/

GRline2(GRnn,GRn,GRvolt,rr,r)
;
*Bi-directional transmission lines
GRline2(GRnn,GRn,GRvolt,rr,r)$(GRline(GRn,GRnn,GRvolt,r,rr))=yes;
alias (GRn,GRnn);
```

Parameter

```
ELlchours(ELl) time in hours in each load segment in the day
ELdaysinseason(ELs,ELday) number of days of each type in a season
ELlcgw(ELl,ELs,ELday,rr) regional load in GW for each load segment
GReleccst(ELl,ELs,ELday,time,r) administered electricity price in USD per MWh
Base_power base power in GVA
GRsuscept(GRn,GRnn,GRvolt,r,rr) electricity susceptance of line GRline in per unit
```

GRdistgen(GRn,ELp,v) coefficient to initially distribute generation to nodes.. sum to 1 in each region
 GRdistload(GRn) coefficient to distribute generation to nodes.. sum to 1 in each region
 GRdiscountfactor(time) discount factors over time, if running a multiperiod analysis
 GRexist(GRn,GRnn,GRvolt,r,rr,v) existing transmission capacity in GW
 GRfixedomcst(GRn,GRnn,GRvolt,r,rr) fixed O&M cost in USD per GW per km
 GRomcst(GRn,GRnn,GRvolt,r,rr) variable O&M cost in USD per MWh
 GRcapital(GRn,GRnn,GRvolt,time,r,rr) capital cost in million USD per GW per km
 GRpurcst(GRn,GRnn,GRvolt,time,r,rr) portion of capital cost attributed to equipment in million USD per GW
 GRconstcst(GRn,GRnn,GRvolt,time,r,rr) portion of capital cost attributed to construction in million USD per GW
 GRdistance(GRn,GRnn) distance for inter- and intra- regional transmission in km
 GRleadtime(GRn,GRnn,GRvolt,r,rr) construction and engineering lead times in years
 GRresist(GRn,GRnn,GRvolt,r,rr) resistance for each voltage class and lines in per unit
 GRanglediffmin,GRanglediffmax upper and lower limits for nodal phase angle differences

Variable

GRpangle(ELl,ELs,ELday,GRn,v,r,trun) Bus phase angles in radians

Positive Variables

GRopandmaint(trun) operation and maintenance cost for transmission grid in million USD
 GRimports(trun) equipment capital cost for transmission grid in million USD
 GRconstruct(trun) construction capital cost for transmission grid in million USD
 GRexistcp(GRn,GRnn,GRvolt,r,rr,v,trun) existing transmission capacity in year t in GW
 GRbld(GRn,GRnn,GRvolt,r,rr,v,trun) built transmission capacity in year t in GW
 GRnodaltrans(ELl,ELs,ELday,v,trun,GRn,GRnn,GRvolt,r,rr) transmission quantity between nodes in TWh
 GRtransloss(ELl,ELs,ELday,v,GRn,GRnn,GRvolt,trun,r,rr) losses in transmission in GW
 ELSupply(ELl,ELs,ELday,trun,GRn,r) electricity supply from all power plants in TWh

Objective is to minimize total transmission costs. O&M costs, investment costs, and electricity purchase from generators (A1)

$DELSup_{ELl,ELs,ELday,t,r}$ are the marginal costs of generation, from the power generation sub-model.

$$\min \left[\sum_t (GRopandmaint_t + GRinvestment_t) GRdiscountfactor_t \right] + \left[\sum_{\substack{(ELp,ELf,ELl,ELs,ELday,v,t,r) \\ \text{only if } ELfuelburn(ELpd,v,ELf,r) > 0}} \left(\begin{cases} \text{if administered, } GRElecst_{ELl,ELs,ELday,t,r} GR discountfactor_t \\ \text{if deregulated, } DELSup_{ELl,ELs,ELday,t,r} \end{cases} \right) \cdot ELSupply_{ELl,ELs,ELday,t,GRn,r} \right]$$

Sums operation and maintenance costs (A2)

Note: The last summation in the equation calculates the electricity transmission cost within the nodes. This term is defined as the total electricity supplied in the node minus the electricity transmitted from the node.

$GRopandmaint_t$

$$\begin{aligned} & - \sum_{\substack{(v,GRn,GRnn,GRvolt,r,rr) \\ \text{only if } GRline(GRn,GRnn,GRvolt,r,rr)}} GRfixedomcst_{GRn,GRnn,GRvolt,r,rr} GRdistance_{GRn,GRnn} \cdot (GRExistcp_{GRn,GRnn,GRvolt,r,rr,v,t} + GRbld_{GRn,GRnn,GRvolt,r,rr,v,t}) \\ & - \sum_{\substack{(ELl,ELs,ELday,v,GRnn,GRn,GRvolt,r,rr) \\ \text{only if } GRline(GRn,GRnn,GRvolt,r,rr) \text{ or } GRline2(GRn,GRnn,GRvolt,r,rr)}} GRomcst_{GRn,GRnn,GRvolt,r,rr} \cdot GRdistance_{GRn,GRnn} GRnodaltrans_{ELl,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} \\ & - \sum_{\substack{(ELl,ELs,ELday,GRn,GRvolt,r) \\ \text{only if } GRnr(GRn,r)}} GRomcst_{GRn,GRn,GRvolt,r,r} \cdot GRdistance_{GRn,GRn} \left(ELSupply_{ELl,ELs,ELday,t,GRn,r} \right) \end{aligned}$$

$$\begin{aligned}
& - \sum_{\substack{GRnn, rr, v \\ \text{only if } GRline(GRn, GRnn, GRvolt, r, rr) \text{ or } GRline2(GRn, GRnn, GRvolt, r, rr)}} GRnodaltrans_{ELI, ELs, ELday, v, t, GRn, GRnn, GRvolt, r, rr} \\
& = 0
\end{aligned}$$

Sums investment costs, if any (A3)

$$\begin{aligned}
GRinvestment_t - \sum_{\substack{(v, GRn, GRnn, GRvolt, r, rr) \\ \text{only if } GRline(GRn, GRnn, GRvolt, r, rr) \\ \text{and newvintage}}} (GRcapitalcst_{GRn, GRnn, GRvolt, t, r, rr} GRdistance_{GRn, GRnn} \\
\cdot GRbld_{GRn, GRnn, GRvolt, r, rr, v, t}) = 0
\end{aligned}$$

An accounting equation to state the any built capacity is bi-directional (A4)

While existing transmission capacity is not fully bi-directional, we here assume that any built capacity is. (only if $GRline(GRn, GRnn, GRvolt, r, rr)$ and newvintage)

$$GRbld_{GRn, GRnn, GRvolt, r, rr, v, t} - GRbld_{GRnn, GRn, GRvolt, rr, r, v, t} = 0$$

Equation to represent the power flow in each transmission line (A5)

Only written for transmission lines connecting GRn and GRnn, where $GRn \neq GRnn$. Since we do not allow the transmission of electricity variable to be negative, this equation is implemented a little differently.

$$\begin{aligned}
& \frac{GRnodaltrans_{ELI, ELs, ELday, v, t, GRn, GRnn, GRvolt, r, rr}}{ELlhours_{ELI} ELdaysinseason_{ELs, ELday}} \\
& - GRsusceptance_{GRn, GRnn, GRvolt, r, rr} (GRpangle_{ELI, ELs, ELday, v, t, GRn, r} \\
& - GRpangle_{ELI, ELs, ELday, v, t, GRnn, rr}) = 0
\end{aligned}$$

Equations to measure losses during transmission (in GW; bi-directional flows) (A6 and A7, respectively)

(from Fitiwi et al. (2016); the base power used is 1000 MVA)

Note: $GRresist_{GRn, GRnn, GRvolt, r, rr}$ are quantified in per unit terms.

$$\begin{aligned}
& \frac{GRresist_{GRn, GRnn, GRvolt, r, rr}}{Base_power} (GRexistcp_{GRn, GRnn, GRvolt, r, rr, v} + GRbld_{GRn, GRnn, GRvolt, r, rr, v, t}) \\
& \cdot \left[\frac{GRnodaltrans_{ELI, ELs, ELday, v, t, GRn, GRnn, GRvolt, r, rr} + GRnodaltrans_{ELI, ELs, ELday, v, t, GRnn, GRn, GRvolt, rr, r}}{ELlhours_{ELI} ELdaysinseason_{ELs, ELday}} \right] \\
& - 0.165 (GRexistcp_{GRn, GRnn, GRvolt, r, rr, v} + GRbld_{GRn, GRnn, GRvolt, r, rr, v, t}) \\
& - GRtransloss_{ELI, ELs, ELday, v, GRn, GRnn, GRvolt, t, r, rr} = 0 \\
& GRtransloss_{ELI, ELs, ELday, v, GRn, GRnn, GRvolt, t, r, rr} - GRtransloss_{ELI, ELs, ELday, v, GRnn, GRn, GRvolt, t, rr, r} = 0
\end{aligned}$$

Constraint to balances existing capacity and built capacity through time (A8) ($GRbld$ is zero during its construction lead time, and its only appears for new-vintage lines)

$$\begin{aligned}
& GRexistcp_{GRn, GRnn, GRvolt, r, rr, v, t} + GRbld_{GRn, GRnn, GRvolt, r, rr, v, t} \\
& - GRexistcp_{GRn, GRnn, GRvolt, r, rr, v, t+1} \geq 0
\end{aligned}$$

Constraint to ensure operation of power lines stays within the existing capacity (A9) ($GRbld$ is zero during construction lead time, if applicable, and its only appears for new-vintage lines)

$$\begin{aligned}
& ELlhours_{ELI} ELdaysinseason_{ELs, ELday} (GRexistcp_{GRn, GRnn, GRvolt, r, rr, v, t} \\
& + GRbld_{GRn, GRnn, GRvolt, r, rr, v, t}) \\
& - GRnodaltrans_{ELI, ELs, ELday, v, t, GRn, GRnn, GRvolt, r, rr} \\
& - GRnodaltrans_{ELI, ELs, ELday, v, t, GRnn, GRn, GRvolt, rr, r} \geq 0
\end{aligned}$$

Power flow in each bus (node) with respect to phase angles (using Kirchhoff's Current Law to conserve energy) (A10)

In the case with three nodes per region, the parameter $GRdistload_{GRnn}$ distributes loads from regions to nodes.

- $ELsupply_{ELI, ELs, ELday, t, GRnn, rr}$ is calculated as supply of electricity in each node. The generators are distributed based on proximity to the node using $GRdistgen_{GRnn}$.
- The load is distributed based on population distribution in each region. In the model, $ELlclw_{ELI, ELs, ELday, rr}$ is all exogenous loads. Terms for the individual sectors' demands that are within KEM are included in the model.

Table B.1

Cost estimates for power generation technologies in 2015.

Source: KAPSARC analysis; ECRA, 2010; IRENA, 2015; IEA and NEA, 2015.

Power generation technology	Capital cost (thousand \$/kW)	Fixed O&M cost (\$/kW/year)	Non-fuel variable O&M cost (\$/MWh)	Design lifetime (years)
Open-cycle gas turbines (OCGT)	1.48	11.2	4.00	30
Combined-cycle plants	1.74	12.4	3.30	35
Conversion of OCGT to combined-cycle plants ^a	0.24	–	–	20
Oil- or gas-fired steam turbine plants	2.12	11.2	1.64	35
Oil-fired steam turbine plants with SO ₂ scrubber	2.57	16.7	4.43	35
Nuclear fission plants	4.90	68.8	6.90	60
PV plants	1.44	26.7	–	25
Parabolic trough CSP (with eight hours of thermal storage)	7.45	70.0	3.00	30
Wind turbines (on-shore)	1.80	45.5	5.90	20

^a Conversion has a lower efficiency than new combined-cycle plants and increases capacity of OCGT by 50 percent.**Table B.2**Heat rates for thermal plants in 2015^a.

Source: Matar and Anwer, 2017.

	Fuels	Eastern operating area	Central operating area	Western operating area	Southern operating area
OCGT	Crude oil		2497		
	Diesel	2190	2175	3281	2193
	Natural gas		13237		
Existing combined-cycle plants	Crude oil		1781		
	Diesel		1688		
	Natural gas		9213		
New combined-cycle plants	Crude oil		1217		
	Diesel		1153		
	Natural gas		6092		
Converted OCGT to combined-cycle plants	Crude oil		1238		
	Diesel		1173		
	Natural gas		6200		
Oil- or gas-fired steam turbine plants	Crude oil		1702		
	Diesel		1613		
	Fuel oil		1532		
	Natural gas		8804		
Oil-fired steam turbine plants with SO ₂ scrubber	Crude oil		1725		
	Diesel		1635		
	Fuel oil		1553		
Nuclear fission plants	Uranium fuel		120		

^a Units for thermal plant's heat rates by fuel: crude oil, diesel & fuel oil is 'barrels/GWh', Natural gas is 'MMBTU/GWh' and uranium fuel is in 'grams/GWh'.

In the case with a single node per region, the parameter is set to unity for each region.

 $ELsupply_{ELI,ELs,ELday,t,GRnn,rr}$

$$\begin{aligned}
& + \left(\sum_{\substack{(v,GRn,GRvolt,r) \\ \text{only if } GRline(GRn,Gnn,GRvolt,r,rr) \text{ or } GRline2(GRn,GRnn,GRvolt,r,rr)}} GRnodaltrans_{ELI,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} \right. \\
& \left. - GRnodaltrans_{ELI,ELs,ELday,v,t,GRnn,GRn,GRvolt,rr,r} \right) \\
& - \sum_{\substack{(v,GRn,GRvolt,r) \\ \text{only if } (GRline(GRn,Gnn,GRvolt,r,rr) \text{ or } GRline2(GRn,GRnn,GRvolt,r,rr)) \\ \text{and } GRnr(GRn,r)}} GRtransloss_{ELI,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} \\
& \cdot ELlhours_{ELI} ELdaysinseason_{ELs,ELday} \\
& \geq ELlhours_{ELI} ELdaysinseason_{ELs,ELday} ELcgw_{ELI,ELs,ELday,rr} GRdistload_{GRnn}
\end{aligned}$$

Appendix B. Key model input data for the power system

This section highlights some of the power generation data used in KEM; the transmission data used is summarized in the body of text. Model inputs for plant design life times and capital and O&M costs are summarized in Table B.1; all costs are denominated in 2015 U.S. dollars. Costs for conventional thermal technologies are based on ECRA (2010), costs for CSP with thermal energy storage were derived from the IRENA (2015), and the average costs for other renewable plants and nuclear are taken from IEA and NEA (2015). We use a discount rate of 6 percent to compute the annualized capital costs for both the transmission and generation segments.

Planned utilization factors that dictate the extent to which plants are taken offline for scheduled maintenance are acquired from ECRA (2010) for each technology. They range from 89 percent for steam turbine and combined-cycle plants, to 92 percent of open-cycle gas turbines. In addition, the advent of renewable generation may cause a further reduction in the capacity factors of some thermal plants; dispatch from thermal plants is an output of the model. For renewable technologies, the capacity factors are determined by the daily resource profiles, as well as any curtailment that may take place. Therefore, the effective capacity factors of thermal and renewable plants are endogenous to the model.

Thermal plant heat rate input by fuel and region of KEM are also shown by Table B.2. The heat rates for conventional thermal plants are derived from actual SEC operation data, sans newly built CCGT plants, which have a thermal efficiency of 55 percent. The value for nuclear plants is estimated from the European Nuclear Society. The heat rate of steam turbine plants with desulfurization is taken as 1.33 percent higher than those without desulfurization.

These technologies compete with one another to meet demand at the least cost, while satisfying the physical constraints of the generation and transmission system. Regional hourly power loads in 2015 are taken directly from SEC. They are processed to adhere to the temporal aggregation structure described in the body of the text.

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