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King Abdullah Petroleum Studies and Research Center

Electricity Transmission Formulations in Multi-Sector National Planning Models: An illustration using the KAPSARC Energy Model

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Summary

The purpose of this study is to assess 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.

Previous versions of KEM used a transshipment formulation for electricity transfer, which basically treats it similar to fuel transport. Electricity transmission formulations, however, represent the physical constraints that govern power flows in real-life. The variability and intermittency of renewable power imposes limitations on the operations of the grid and models that do not incorporate a representation of electricity transmission may miss key insights, particularly when large-scale deployment of renewable technologies is contemplated. This study illustrates the methodology and consequences of moving from a transshipment formulation of KEM to one which includes transmission with a single or multiple nodes within each region.

Our results show:

> The optimal investment in photovoltaics (PV) and the marginal costs of delivering electricity change considerably when transmission of electricity both within regions and between regions is incorporated into the model compared to the simple transshipment formulation.

> The number of nodes in each region described by the model alters the model outcomes more than whether the model incorporates transmission losses or not. However, a version of KEM with a single node in each region for transmission and without accounting for transmission losses still provides valuable insight compared with the transshipment formulation, while keeping the model size tractable.

> Introducing transmission into the model gives results that are more affected by the operations of the power system than by the fuel and technology mix. The market-clearing price of natural gas in a deregulated environment only changes slightly because reduced PV deployment (compared to the transshipment version) is mostly offset by a minor increase in dispatch of gas-fired generation.

> In a regulatory model where location marginal prices are passed on to consumers, the new model captures the changes in the marginal costs of electricity delivery at the transmission nodes whereas the simpler transshipment formulation would miss this insight. In other words, the transmission component is needed for planning a system where location marginal prices are passed on to consumers.

Introduction

Large-scale national policy models date back to the 1970s (Hall and Buckley 2016), and have adopted different levels of detail with the ultimate purpose of informing policy decisions. These models make trade-offs in what to represent and how to represent it, while making the models tractable and relatively easy to solve.

In partial economic equilibrium models, such as the core of the National Energy Modeling System (NEMS) of the Energy Information Administration (EIA) and the International Energy Agency's TIMES (The Integrated MARKAL-EFOM System), power generation expansion models have been understandably favored to electricity transmission models. They have typically adopted transshipment, or transportation, formulations of power flows that do not adhere to Kirchhoff's Current and Voltage Laws. Taking these laws into account, 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 via all paths between generators and load. Models that rely on a transshipment method in place of a proper transmission model generally underestimate additional transmission capacity requirements (Krishnan et al 2016). The aim of this paper is to assess the effects of introducing a transmission component in a national planning model. Specifically, would the addition of transmission alter the decisions of the sectors linked to it?

For this case study, a transmission sub-model is integrated in the KAPSARC Energy Model (KEM) for Saudi Arabia. The model already consists of several economic sectors, such as 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 the 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 transmission component can directly influence policy assessments. Firstly, we hypothesize that introducing transmission constraints in the model can impact power generation investment decisions, especially in renewable technology. Whereas the basic model could integrate large quantities of variable renewable technologies if fuel prices were sufficiently high, it did not consider the possible intermittent congestion arising in the regional transmission lines or the physical limitations of the grid. Secondly, the marginal cost of delivering electricity is expected to change as a result of different investment decisions, which may affect the levels of electricity demand.

There may also be tertiary effects that have wider ramifications on the economy. One example is the domestic market-clearing price of natural gas. Since the technology mix is expected to change in power generation, fuel consumption may also change, and therefore the consumption of natural gas and its level of scarcity may change.

These ideas, coupled with the lack of a proper transmission representation in existing national planning models, motivated this work. Compounding all these changes, our modeling analysis generates about $20 billion in avoided full cycle investment in power plants in the long run. To get an idea of the size of the sector, the operating revenue of the local power utility, the Saudi Electricity Company (SEC), was around $11 billion in 2015 (SEC 2016). The paper contextualizes these savings.

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 by displaying and discussing the results.

Electricity Transmission Representation in Other National Energy Policy Models

Studies that have explored the policy relevance of adding a transmission component to multi-sector national planning models are limited. Lehtila and Giannakidis (2013) highlighted the importance of having it 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, 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 currently in use.

While not in the context of planning models that span multiple sectors, Krishnan et al (2016) performed a review of combined generation and transmission expansion models, and their impact on policy assessments. They show and discuss that a model combining both produces less 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 member countries of the Association of Southeast Asian Nations (ASEAN). They used one to three transmission nodes for each member country.

The Regional Energy Deployment System (ReEDS) is a model of the U.S. 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 U.S. 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 to populate them with data and solve them within a reasonable timeframe.

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 2014)	Optimization	The contiguous United States, broken into 22 regions.	Transshipment
TIMES (Loulou et al 2005)	Optimization	For generic use (for any particular region or country).	Transshipment
KEM (before transmission addition; KAPSARC 2016)	Equilibrium	Saudi Arabia, broken into four regions.	Transshipment
PLEXOS (Energy Exemplar 2017)	Optimization (commercial software taking an integrated view of 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).

Source: KAPSARC.

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). Having multiple sectors is vital in this case because all consumers of natural gas compete over a scarce resource, and Saudi Arabia has a policy where no primary fuels are imported. 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.

The formulation of the 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. 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.

Currently, KEM has a transshipment formulation, which does not adhere to physical constraints that govern the transfer of electricity, like Kirchhoff's laws. It is critical that we point this 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 are shown in Figure 1 for the latter case. For the single-node case, physical laws are still satisfied for interregional transmission, assuming one line exists 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 have not been built, but the model allows for their construction.

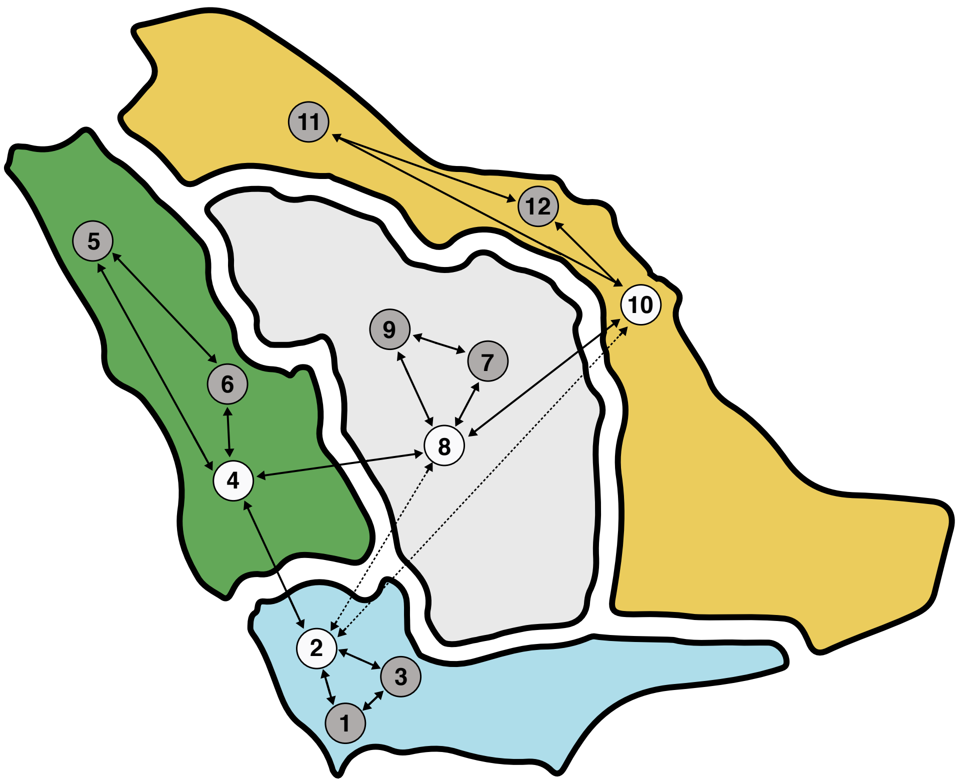

Figure 1. Distribution of transmission nodes in each of the four regions in KEM.

Source: KAPSARC.

Transmission lines are modeled only within the country for the purpose of the KEM, although price-based trading with the rest of the Gulf Cooperation Council (GCC) countries and Egypt is planned in the future.

Figure 2 illustrates how transmission is integrated with other sectors in the KEM. The solid lines between the sectors show the flows of physical goods. The transmission system operator (TSO) is hence treated as a separate entity from the generation sector. Its sub-model is linked with the electricity generators and satisfies the power demands in the economy.

An alternating current optimal power flow (ACOPF) problem properly models the physical phenomena that govern electricity transmission (Eldridge et al 2017). Due to its computational complexity, however, most researchers prefer a direct current OPF (DCOPF) representation as it is a linear approximation of the problem (e.g., Hedman et al 2009; Lehtila and Giannakidis 2013); therefore, it is used in this analysis. The set of equations and constraints in the Appendix (A1-A10) define the implementation of the DCOPF problem used in the KEM. The model abides by the physical laws, such as Kirchhoff's current law, that ultimately result in energy conservation. Our model is similar to that of Hedman et al (2009), but it is formulated as a continuous problem, to retain its suitability for linkage with the KEM; dual variables of discrete equations lose their economic sensibility.

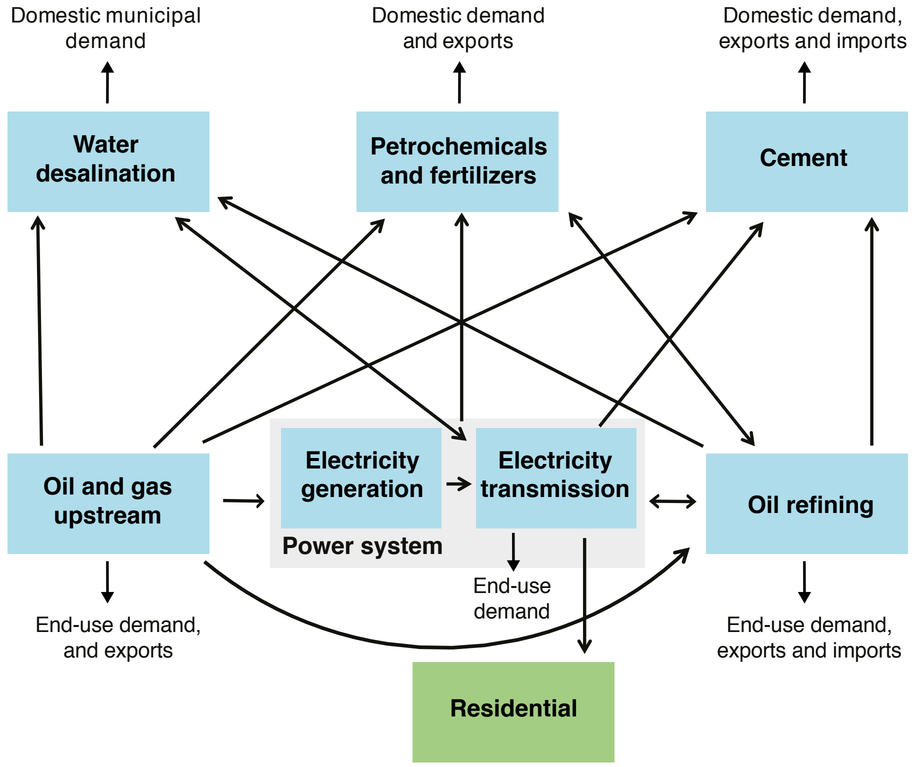

Figure 2. Sectors modeled in this version of KEM.

Source: KAPSARC.

The objective of the problem is to minimize the total cost of the transmission system. This includes any investment, fixed and variable operation and maintenance (O&M) costs, and electricity purchased from the generators. The electricity is traded at marginal cost of supply between generators and TSOs. Currently, the grid in Saudi Arabia is controlled by the major generation utility. The transmission component is linked with the rest of the 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 the Appendix (A10).

Since DCOPF models typically exclude losses, we test a case where we have transmission losses modeled. 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, such as investment decisions, and for the sake of completeness. We added the 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 by Equations A6 and A7 in the Appendix. 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.

The 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); this includes the updated capital costs of power plants. 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 were obtained from the Energy Technology Systems Analysis Programme (2014), and inter-regional transmission capacities were acquired from correspondence with the Electricity and Co-generation Regulatory Authority (ECRA), the Saudi power regulator. There are no accessible data for intra-regional capacities, so we set them to be higher than any of the regional demand in the system. This, however, does mean 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 Saudi 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 that previously used in the KEM. 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 radians, 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 2015 fuel prices and natural gas supply quotas. 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. For more information on Saudi industrial fuel prices, see Matar et al (2016, 2017). Results for three cases will be discussed:

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

Results and Discussion

In this section, we examine 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 the 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.

Investment decisions are a key metric to judge the effects of having a proper transmission formulation on policy assessments. As shown in Figure 3, there is a clear difference between a version of KEM with and without the transmission component. 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.

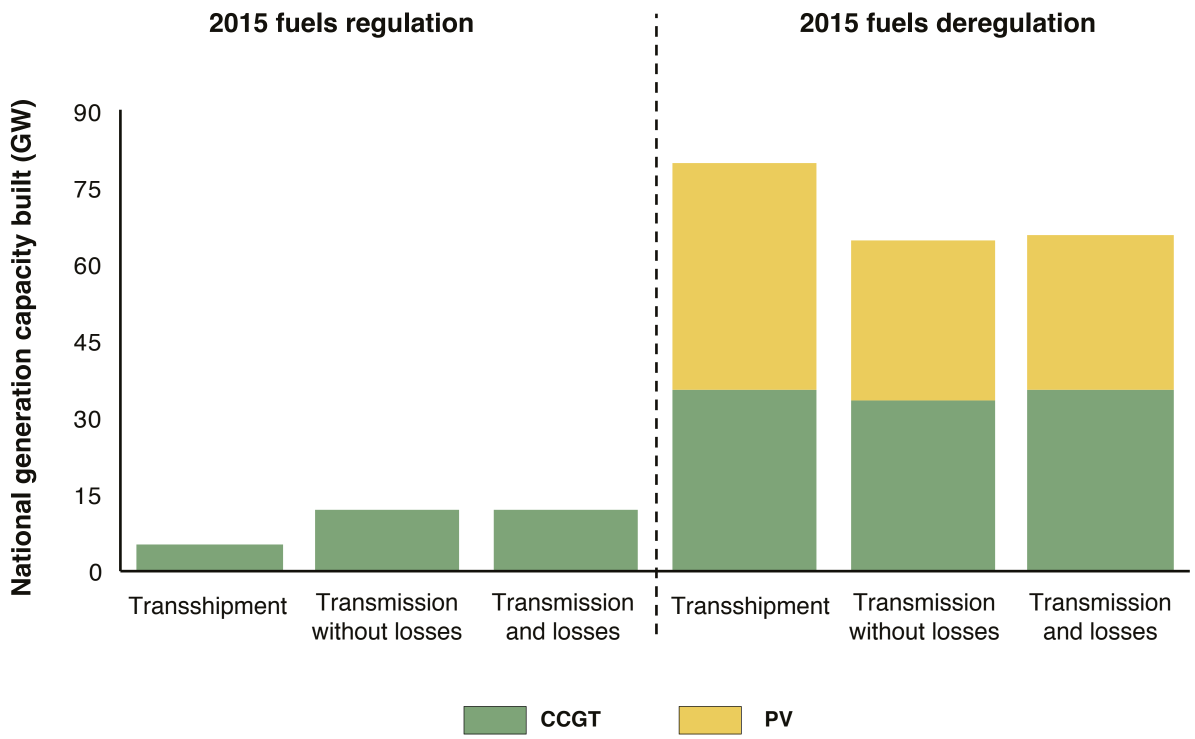

Figure 3. Generation capacity that is built using KEM in the fuel pricing scenarios with and without a transmission component.

Source: KAPSARC analysis.

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 supply constraint of natural gas, and the fact oil is excessively costly as a result of deregulation, the remaining electricity demand is met by PV plants (see Matar et al 2017). We see investments in more than 10 GW of PV forgone when a transmission representation is included. Based on a full capital cost at the time of $1,436 per kW, that is almost $20 billion in unspent expenditure in the long run. There is little difference in the level of national investments made in a model that has transmission losses and one that does not. Furthermore, Table 2 shows that PV installations are similar when comparing models that have a transmission component; however, the CCGT deployment is altered in the central and eastern regions of Saudi Arabia.

The lower PV deployment is a result of the operability of the transmission system. With previous versions of the 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 with previous versions.

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	Transmission without losses	Transmission and losses
South	**CCGT**	3.5	3.1	3.5
	PV	17.4	3.6	4.0
West	**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
East	**CCGT**	18.0	20.1	15.3
	PV	0	6.1	4.3

Source: KAPSARC analysis.

In a scenario where fuel 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. In versions of the KEM that have a transmission representation, this equates to the locational marginal price (LMP). The LMP factors in the congestion along a particular transmission line at a particular time of the day. Figures 4 and 5 illustrate this metric for an average summer weekday in the central and western regions, respectively. The regions are single entities in the KEM without the transmission component and, as Figure 1 shows, nodes 4, 5 and 6 comprise the western region, and nodes 7, 8 and 9 constitute the central area.

The numbers show, on average, that the marginal cost nearly doubles compared with a version of the KEM that uses a transshipment model. That could have large demand response effects if this cost influences the price for consumers. Furthermore, the effect of incorporating transmission losses is also limited on this metric compared to the transshipment case.

Figures 4 and 5 also show there is a surge in the LMPs during 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 p.m. to 9 p.m. on a summer weekday from nodes 4 and 5 to node 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.

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 transmission component.

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

Source: KAPSARC.

Note: For comparison, the regulated natural gas price was 0.75 $/MMBTU in 2015.

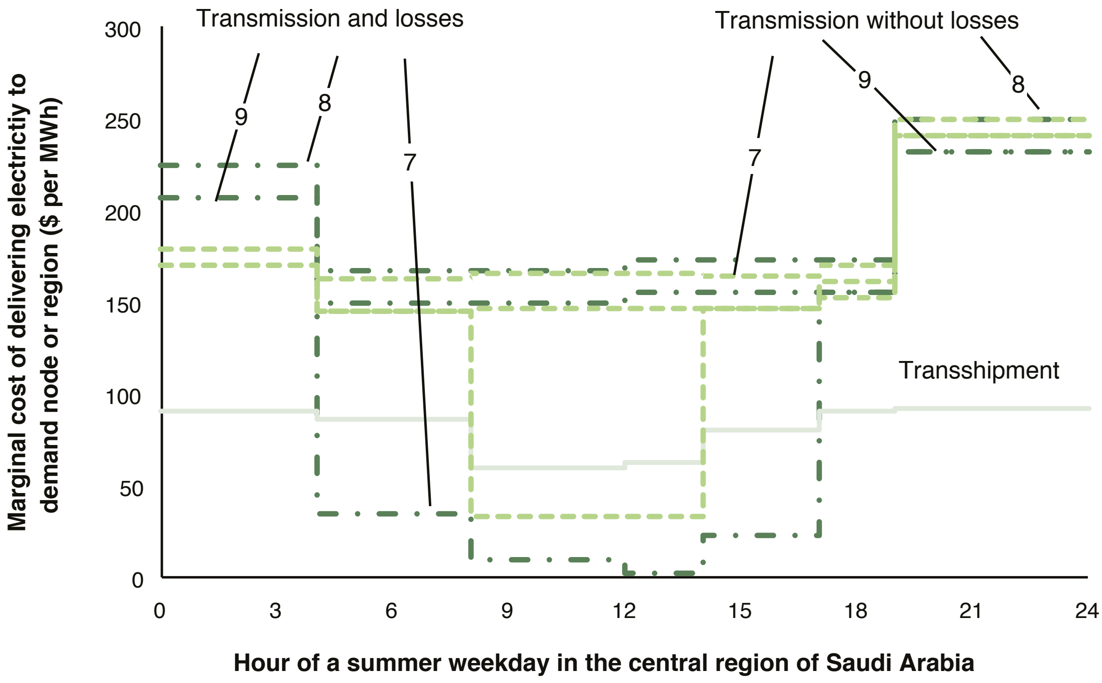

Figure 4. Marginal cost of electricity delivery in 2015 fuels deregulation with and without a transmission component in the central region on a summer weekday.

Source: KAPSARC analysis.

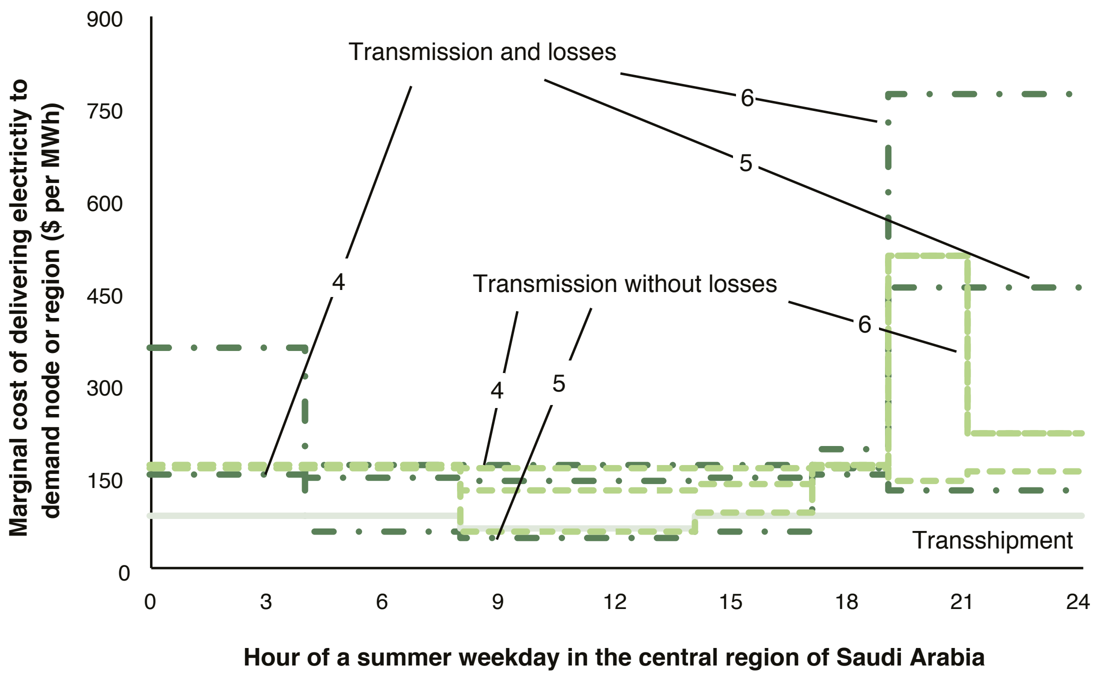

Figure 5. Marginal cost of electricity delivery in 2015 fuels deregulation with and without a transmission component in the western region on a summer weekday.

Source: KAPSARC analysis.

Also, there is a large change in aggregate power system cost with transmission in place. In the original version of the KEM, despite the vast area covered by a single region, intra-regional transfer of electricity was characterized by a single value of distance, and thus one variable O&M cost parameter. In this version, we could model the specific distances required for transmission between the nodes. As a result, we have significantly higher costs to the entire power system.

We looked at the domestic market-clearing price of natural gas as well, to examine the wider economic impacts of adding transmission. The price is relatively stable, especially considering the model would have a “simplification” error compared to reality. We had thought if having a transmission network would affect fuel use decisions made by the generators, its effects may permeate to the rest of the economy as gas supply constrains improve or worsen. In this respect, there is an 11 percent increased use of natural gas in the power system in a case with transmission than without; this is understandable given the lower PV deployment levels. That rise translates to a lower increase in the natural gas price.

KEM with transmission formulation and a single node in each region

To test the effect of having more extensive regional disaggregation versus just a transmission 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 the KEM.

Shown in Table 4, there are some differences in the marginal cost of electricity delivery, but certainly starker in the transmission versus transshipment cases. 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.

Comparison of model performance across different versions of the model

Since the 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. 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 the KEM.

Given that extra nodes do not alter the investment decisions and the LMPs significantly, we propose to use the KEM with transmission and a single node per region, but either with or without losses. The change in the solution run-time and the number of variables with such model specifications are manageable; however, versions of the KEM with three nodes per region required 4 to 6 times more time to solve. If the 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 no-loss 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 hours to solve, depending on the planning horizon of interest.

Table 4. Comparison of the results in Table 3 with three nodes and one node per region.

		KEM with transshipment	KEM with transmission without losses		KEM with transmission 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* (billion $)	2015 fuels deregulation	4.73	3.30	3.15	3.18	3.23

Source: KAPSARC analysis.

Note: Estimating the full capital cost of utility-scale PV in 2015 as 1,436 $/kW, discounted at 6% over 25 years.

Conclusion

This paper aims to show the impact of including an electricity transmission element in a multi-sector national planning model. Most of these types of models rely on transshipment formulations in place of transmission. Yet, recent literature has stressed the fact that having transmission constraints is necessary with renewable power generation deployment.

To do this, we added a DCOPF formulation in the KEM 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 the KEM with transmission versus transshipment. 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 becomes relevant when we run it in multi-period fashion. Having one or three nodes per region in the transmission formulation yielded a large effect on the solution time; however, both versions generated similar average LMPs for a case in which fuel prices are deregulated. They were lower with a single node for a regulated fuel pricing case, but still higher than the transshipment version. The largest difference in the two versions of a 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 yield similar costs.

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

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Appendix: Transmission Model Formulation

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 and the lines connecting them are shown in Figure 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/
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,
                                                 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 daily
ELdaysinseason(ELs,ELday) 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 distribu te generation to nodes.. sum to 1 in each region
GRdistload(GRn) coefficient to distribute generation to nodes.. sum to 1 in each region
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

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

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

$$
\begin{aligned}
& min\left[\sum_{t}(GRopandmaint_t + GRinvestment_t)GRdiscountfactor_t\right] \\
& + \left[\sum_{\substack{(ELp,ELf,ELl,ELs,ELday,v,t,r) \\ only\ if\ ELfuelburn(ELpd,v,ELf,r)>0}} \left(\begin{cases} if\ administered,\ GReleccst_{ELl,ELs,ELday,t,r}GRdiscountfactor_t \\ if\ deregulated,\ DELsup_{ELl,ELs,ELday,t,r} \end{cases}\right) \right. \\
& \left. \cdot ELsupply_{ELl,ELs,ELday,t,GRn,r} \right]
\end{aligned}
$$

A2: Sums operation and maintenance costs

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.

$$
\begin{aligned}
& GRopandmaint_t \\
& - \sum_{\substack{(v,GRn,GRnn,GRvolt,r,rr) \\ only\ if\ GRline(GRn,GRnn,GRvolt,r,rr)}} GRfixedomcst_{GRn,GRnn,GRvolt,r,rr} GRdistance_{GRn,GRnn} \\
& \cdot \left(GRexistcp_{GRn,GRnn,GRvolt,r,rr,v,t} + GRbld_{GRn,GRnn,GRvolt,r,rr,v,t}\right) \\
& - \sum_{\substack{(ELl,ELs,ELday,v,GRnn,GRn,GRvolt,r,rr) \\ only\ if\ GRline(GRn,GRnn,GRvolt,r,rr)\ \boldsymbol{or}\ GRline2(GRn,GRnn,GRvolt,r,rr)}} GRomcst_{GRn,GRnn,GRvolt,r,rr} \\
& \cdot GRdistance_{Grn,GRnn} GRnodaltrans_{ELl,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} \\
& - \sum_{\substack{(ELl,ELs,ELday,GRn,GRvolt,r) \\ only\ if\ GRnr(GRn,r)}} GRomcst_{GRn,GRn,GRvolt,r,r} \\
& \cdot GRdistance_{GRn,GRn} \left(ELsupply_{ELl,ELs,ELday,t,GRn,r} \right. \\
& \left. - \sum_{\substack{GRnn,rr,v \\ only\ if\ GRline(GRn,GRnn,GRvolt,r,rr)\ \boldsymbol{or}\ GRline2(GRn,GRnn,GRvolt,r,rr)}} GRnodaltrans_{ELl,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} \right) \\
& = 0
\end{aligned}
$$

A3: Sums investment costs, if any

$$
\begin{aligned}
& GRinvestment_t \\
& - \sum_{\substack{(v,GRn,GRnn,GRvolt,r,rr) \\ only\ if\ GRline(GRn,GRnn,GRvolt,r,rr) \\ \boldsymbol{and}\ new\ vintage}} \left(GRcapitalcst_{GRn,GRnn,GRvolt,t,r,rr} GRdistance_{GRn,GRnn} \right. \\
& \left. \cdot GRbld_{GRn,GRnn,GRvolt,r,rr,v,t}\right) = 0
\end{aligned}
$$

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

While existing transmission capacity is not fully bi-directional, we here assume that any built capacity is.

$$
(only\ if\ GRline(GRn, GRnn, GRvolt, r, rr)\ \boldsymbol{and}\ new\ vintage)
$$

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

A5: Equation to represent the power flow in each transmission line

Only written for transmission lines connecting GRn and GRnn, where GRn≠GRnn.

$$\frac{GRnodaltrans_{ELl,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr}}{ELlchours_{ELl}ELdaysinseason_{ELs,ELday}} - GRsusceptance_{GRn,GRnn,GRvolt,r,rr}\left(GRpangle_{ELl,ELs,ELday,v,t,GRn,r} - GRpangle_{ELl,ELs,ELday,v,t,GRnn,rr}\right) = 0$$

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

(from Fitiwi et al (2016); the base power used is 1,000 MVA)

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

$$\frac{GRresist_{GRn,GRnn,GRvolt,r,rr}}{Base\_power}\left(GRexistcp_{GRn,GRnn,GRvolt,r,rr,v} + GRbld_{GRn,GRnn,GRvolt,r,rr,v,t}\right) \cdot \left[\frac{GRnodaltrans_{ELl,ELs,ELday,v,t,GRn,GRnn,GRvolt,r,rr} + GRnodaltrans_{ELl,ELs,ELday,v,t,GRnn,GRn,GRvolt,rr,r}}{ELlchours_{ELl}ELdaysinseason_{ELs,ELday}} - 0.165\left(GRexistcp_{GRn,GRnn,GRvolt,r,rr,v} + GRbld_{GRn,GRnn,GRvolt,r,rr,v,t}\right)\right] - GRtransloss_{ELl,ELs,ELday,v,GRn,GRnn,GRvolt,t,r,rr} = 0$$

$$GRtransloss_{ELl,ELs,ELday,v,GRn,GRnn,GRvolt,t,r,rr} - GRtransloss_{ELl,ELs,ELday,v,GRnn,GRn,GRvolt,t,rr,r} = 0$$

A8: Constraint to balances existing capacity and built capacity through time

(GRbld is zero during its construction lead time, and its only appears for new-vintage lines)

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

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

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

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

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

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

Notes

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About the Project

We developed the KAPSARC Energy Model (KEM) for Saudi Arabia to understand the dynamics of the country's energy system. It is a partial equilibrium model formulated as a mixed complementarity problem to capture the administered prices that permeate the local economy. KEM has been previously used to study the impacts of various industrial fuel pricing policies, improved residential energy efficiency on the energy economy, the feasibility of installing coal-fired power plants in Saudi Arabia, and reforming residential electricity tariffs. In the present paper, we use it to assess the effects of introducing an optimal power flow formulation for electricity transmission on policy-relevant metrics.

KAPSARC

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