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Simulating Generalised Locational Marginal Pricing for Power Markets in East Africa

Geoffrey Aori Mabea*

Energy Regulators Association of East Africa, Energy Regulation Centre of Excellence, Arusha, Tanzania.
*Email: geoffrey.mabea@energyregulators.org

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ABSTRACT

There is an enormous opportunity for adopting a wholesale electricity market under locational marginal pricing. Besides ensuring competition and accounting for network congestion, the price signal reflects a space-time electricity economy. This paper examines the prospects of introducing a single East African electricity market in five selected partner states. It reports on a pioneering effort to simulate the coupling of power markets, estimate locational marginal prices, and determine the economic benefits of cross-border power trade and competition across these five countries. The nodes representing the primary power systems in these five countries are simulated in an optimal power flow model using optimisation software GAMS. The total welfare of electric power market integration is estimated at $ 4.8 million/h, representing a welfare gain of $ 2.6 million/h, thus, net total welfare increases by 118%. The simulation also investigates the implications for locational prices and power flows under constrained and unconstrained scenarios. To secure the benefits of an integrated electricity market, it is vital to pursue significant institutional restructuring, a robust transmission infrastructure, and the harmonisation of energy policies.

Keywords: Electricity Market Integration, East Africa, Locational Pricing, Congestion, Optimal Power Flow, Simulation
JEL Classifications: D470, L940, L980

1. INTRODUCTION

Electricity market integration is crucial for capturing efficiency gains, enhancing cross-border trade, sending appropriate market signals to investors, promoting competition, and contending with climate change (Nowak, 2010; Mulder, 2015; Newbery, 2018). The architecture of an integrated electricity market involves numerous design aspects, such as power pooling and exchanges, trading and market clearing rules, competition in generation, transmission regulation, congestion management, and balancing services (Chao and Wilson, 2001; Silva-Rodriguez et al., 2022). However, the electricity markets of East Africa Community (EAC) member countries are hardly integrated. Whether or not the gains from trade are largely captured depends on the technical, market, and regulatory arrangements supporting the interconnection of EAC member countries. What are the economic welfare implications of electricity market integration in East Africa?

The tendency for fragmentation in the infrastructure for electric power trading reflects the struggle to pursue economic integration in East Africa. Founded in 1967, the EAC seeks to promote economic growth and regional economic integration based on a customs union, common markets, monetary union, and political federation (EAC, 1999-2020). Its member countries, Burundi, Kenya, Rwanda, Tanzania, Uganda, and (most recently) Southern Sudan, aspire to secure reliable electricity supply and attract investments in the electric power sector. Nevertheless, harmonising the design or implementation of electricity policy looks weak. The electricity trade in the EAC is currently based on individual arrangements (i.e., so-called "over the counter"). EAC member countries enter into long-term bilateral or trilateral agreements to exchange excess capacity at a determined price when peak demand in one country exceeds its available domestic capacity. A set of procurement and wheeling agreements to deliver electric power from Kenya through Uganda to Rwanda is feasible only if Kenya and Uganda reinforce their respective transmission grids to minimise transmission losses and reduce congestion (NCIP, 2014). Notwithstanding the coordination efforts of a regional project unit, the various plans in the EAC to establish or upgrade transmission lines are implemented through the actions of domestic electric power utilities responsible for their respective systems (NCIP, 2014). Thus, the insufficient interconnection of physical and institutional infrastructure threatens the efficiency of operation or expansion decisions in EAC electric power markets.

This paper reports on a pioneering effort to simulate the integration of electric power markets in East Africa under locational marginal pricing. It is the first study to estimate locational marginal prices, congestion, and economic welfare of an integrated electricity market consisting of five EAC member countries: Burundi, Kenya, Rwanda, Tanzania, and Uganda. The model, an optimal power flow reflecting loads, generation plants, and transmission lines, is implemented in optimisation software GAMS. The paper's main contribution is to show that in the short run, the total welfare of electric power market integration is about $ 4.8 million/h, representing a welfare gain of $ 2.6 million/h, an increase in net welfare of 118%. The integration benefits imply that the region is attractive to investors, and the transmission infrastructure becomes cost-effective. Arguably, increases in total economic welfare resulting from changes in producers' surplus and consumer welfare imply that investment in transmission infrastructure, especially between high-price locations to low-price locations, could lead to price falls in high-price locations. Therefore, consumers' benefit increases while the producers lose. However, our argument suggests that it is beneficial for the community to invest in the transmission network to realise the total benefits for the East Africa region.

As far as we could discern, our paper is substantive, unlike any other in the literature on several cognate fields in economics, engineering, or regulatory policy. Section 2 expounds on the literature on electricity market integration. Section 3 describes the theory and model. Section 4 expounds on the methodology and data. Section 5 provides the results of calibrations and simulations and draws implications. Finally, section 6 offers a conclusion.

2. LITERATURE REVIEW

Since introducing the electricity markets integration concept, studies into welfare gains in integrated electricity markets have emerged in various markets to analyse the benefits of introducing the electricity markets. Such studies are, however, sparse. Therefore, it is befitting to point out that electricity integration studies vary depending on the approach angle. Firstly, integrating renewable energies into the system is an approach that has been extensively researched owing to the nature of the renewable resources (low load factors) and the impact it has on the grid. Secondly, there can be an estimation of the benefits of adding a link (transmission line) to existing markets such that the markets in question are coupled up with a high-voltage conductor. Lastly, the approach that is discussed in this research delves into coupling the electricity markets where there exists a single Independent System Operator (ISO) that receives bids and demand from the market players and optimises to identify a marginal clearing price that can be used to settle the demand and supply for the region. This is referred to as the auction process. Newbery et al. (2016) and updated the findings by ACER (2013) by looking at ex-post benefits of EU electricity market integration because of market coupling and arrived at the order of €2.5bn to €4bn/year. This study shows that these benefits were primarily derived from a well-coordinated investment in renewables. At the same time, the decline in generation and transmission costs and physical system efficiency improvement was attributed to the high level of increased integration.

Pellini (2014) used a novel econometric approach to examine the benefits of coupling the Italian electricity market and found that coupling increased welfare gain by €33M/year. Schmid and Brigitte (2015) quantified the benefits of increased electricity market integration in the pan-European electricity system using the LIME-EU+ model by analysing various decarbonisation scenarios and arrived at a decrease of 3.5% of total system costs over the period 2010-2050.

Neuhoff et al. (2013) analysed the benefits arising from a considered most efficient form of market integration against nodal pricing for the European market, excluding the UK, Ireland, Sweden, and Finland. As indicated in Table 1, an estimated annual cost saving of between €0.8Billion and €2Billion for fuel cost was arrived. Mansur and White (2009) compared the gains from pre and post-PJM markets and updated the results to 2012 to review the performance of the PJM market since moving from zonal to nodal pricing. Ott (2010) extended the study to evaluate the total benefits of PJM efficient pricing (nodal) and gave an indicative figure of $ 2.2 billion/year. Meeus (2011) measured the welfare gains arising from pre and post Price Coupling (PC) on the 600MW Kontek HVDC East Denmark to Germany, which insinuated that the gains could be at least €10M/year. The extension of EU integration is likely to increase efficiency gains, as Böckers et al. (2013) estimate welfare gains at €250 Million if the electricity markets are integrated as opposed to remaining as national markets.

Oliver (2013) summarized the ASEAN Energy Market Integration (AEMI) research on the benefits of having a fully integrated electricity market in the ASEAN Electricity Market. The study concluded that the cost associated with the system was likely to reduce by between 3 and 3.9%, with an associated remarkable increase of real GDP by between 1 and 3%. Hakam (2018) simulates nodal pricing in the Indonesian power system and arrives at total welfare of $ 1.8 million.

The financial viability of the power infrastructure investment for the Greater Mekong Sub-region (GMS), ASEAN Power Grid (APG) and ASEAN plus China and India (ASEAN+2), as indicated by Li and Youngho (2015) showed that if the countries

Table 1: Studies on benefits resulting from integrating electricity markets

Author	Region	Scope	Methodology	Value
(Pellini, 2014)			Regression	
(Neuhoff et al., 2013)	EU excluding UK, Ireland, Sweden, and Finland	Effect of additional integration in EU electricity market and the impact of additional wind	Simulation	Annual cost saving of between €0.8 Billion and €2 Billion
(Oliver, 2013)	ASEAN		Simulation	The cost associated with the system is likely to reduce by between 3% and 3.9%
(Matsuo et al., 2015)	ASEAN		Simulation (Cost-Benefit Analysis using: Optimal power generation planning and Supply reliability model	Cost-saving reaching $10 Billion by 2035
(California ISO, 2015)	US electricity markets		Simulation (Qualitative analysis and RPS calculator)	Between $ 3.4 billion and $9.1 billion reduction in shared costs within the first 20 years
(Newbery et al., 2016)	EU	EU interconnector cop	Simulation	Market coupling and arrived at the order of €2.5bn to €4bn/year
(Mansur and White, 2012)	USA	Pre and post-PJM markets integration	Simulation (Nodal pricing and OPF)	Increase in benefits by $180 Million/year

optimised transmission development and allowed up to 80% of domestic power to be met by trade with other countries, the net savings would be $11Billion. The study further found that the acceleration of projects at the GMS level should be given priority so that the integration of these three regions could benefit from the economies of scale.

Matsuo et al. (2015) applied an optimal power generation planning model and supply reliability evaluation model to assess the effect of international power grid interconnection in the ASEAN region. The study covered 12 Asian countries using the dataset published by Platts and assumed a 1% transmission loss for every 100 km of AC transmission line and 2% for DC lines. The results indicated a substantial economic benefit arising from the interconnection because of the likelihood of a cut in the cumulative cost reaching $10 Billion by 2035 and a further cut of at least $ 15 Billion by 2050.

Two main methods have been applied in quantifying the benefits of integrating electricity markets; they are based on the whole system simulation or evaluation of individual interconnectors. The first method involves simulating the entire market or some region of interest and comparing the results with when it is integrated or not integrated. The second method consists of analysing individual interconnectors before and after expansion (Newbery et al., 2016; Pudjianto et al., 2013). The available literature points to the already integrated markets, especially in developed economies. However, this study is yet to be carried out in East Africa. This research, therefore, attempts to quantify the welfare of integrating the EAC electricity market through whole system simulation.

The lack of an agreed approach to quantifying welfare benefits has triggered many discussions recently on how well to quantify the actual benefits-consequently sparking many questions about the reliability of the methods that have been applied primarily in the interconnected networks. This is why we get many different results in any analysis carried out in any single market. For example, ACER/CEER (2015) indicated that the various attributes that sum up to benefits from electricity market integration are not directly convergent. This is the reason ACER/CEER (2013), ACER/CEER (2014), and Newbery et al. (2016) have now embarked on calculating the cost of not attaining a fully integrated market.

This, however, calls for further research into harmonising the models for calculating the actual benefits. All the methods that have been applied, as shown in Tables 1 and 2, indicate the various attempts to analyse the electricity markets and the benefits accruing from the market coupling. These studies have examined the already existing power exchanges. However, ASEAN is still in the process of integrating the markets. Interestingly, there is no such study carried out in Africa.

3. THEORY OF ELECTRICITY MARKET INTEGRATION

The shadow price at the power balance at a given bus gives the bus's locational marginal price (LMP). The LMP acknowledges location or node position, which is vital and, therefore, is reflected in the final electricity price. This is different from the zonal pricing in which there is a uniform price in each region or country regardless of the transmission congestion expected in the region.

The LMP design is based on the nodal price at a point in the network equal to the marginal cost of energy at that node (Green, 2007). It was first developed by Schweppe et al. (1988) under the assumption that if an Optimal Power Flow (OPF) solution is obtained for a given system, then competition in the market can be reached. This implies that given a generator paying at LMP for energy supplied and ancillary services for a given bus, the OPF's optimal solution at that specific bus for the generator is also profit maximising for the firm. Nodal pricing has been implemented in countries like Argentina, Chile, New Zealand, Russia, Singapore, and some USA states; for example, California, New England, New York, PJM, and Texas. Recently, several pieces of research have been carried out

Table 2: Studies on benefits resulting from integrating electricity markets "continued"

Author	Region	Scope	Methodology	Value
(Ott, 2010)	USA	Reviewed work was done by (Mansur and White, 2012) in 2009	Simulation	
(Böckers et al., 2013)			Simulation	
(Weber et al., 1999)		The impact of using price dependent (real and reactive) to estimate welfare maximisation.	Simulation (OPF in price-dependent spot price)	Although the use of reactive power spot price is subject to debate, it is vital to bear in mind the capital costs of installing the reactive power components, such as the capacitor banks.
(Oggioni et al., 2014)	Indonesia	Market coupling	Simulation	Total welfare $1.8 Million
(Hakam, 2018)		Introduced nodal pricing in the Indonesian market	Simulation	

to ascertain the benefits of moving from zonal to nodal pricing, for example, (Van der Weijde and Hobbs, 2011).

Green (2010) explores the impact of integrating intermittent renewable energy into the British system to evaluate the adequacy of the spatiality of prices and the use of bilateral trading to respond to changes in generation and demand. The study argues that nodal pricing allows for efficient allocation, especially in competitive markets where the demand is uncertain and is prevalent in renewable energy production. Ruderer and Zöttl (2012) compare LMP versus zonal or one-price market designs based on the transmission network's type, generation technology and investment level. They conclude that both designs deliver efficient dispatch. However, uniform pricing, such as the one used in the British system, may result in a higher generator payoff.

Application of uniform pricing can lead to distortion of the generation technology mix and thus lead to inefficient investment in the transmission infrastructure (Eicke and Tim, 2022). The locational Marginal pricing model has also been compared to market coupling in large markets. Oggioni et al. (2014) compare LMP and Market coupling, where wind technology policies and many economic agents exist in the power system. The study observes that LMP and Market coupling evolve similarly if wind penetration is constrained to a limit. However, LMP pricing continues to exhibit stability even when the limit is exceeded.

LMP has been identified as one of the efficient ways of congestion management and, to no small extent, is evidence of efficient production investment (Neuhoff et al., 2011; Holmberg and Lazarczyk, 2012; Wang et al., 2014; Kunz et al., 2017; Hotz and Utschick, 2017; Tan et al., 2022; Conejo, 2023).

LMP is advantageous to consumers in areas with high power generation but low transmission constraints. It is also possible that generators, especially with the low-capacity generation with low marginal production cost, are incentivised to invest in distributed areas. Even with a weak transmission network, they can submit a low bid and yet get paid for full LMP for a given period. However, LMP also promotes the need to invest in weak transmission lines where significant congestion levels are likely to occur. Large power generators are likely to suffer from power generation inflexibility.

4. METHODOLOGY AND DATA DESCRIPTION

We chose 17 nodes (major subsystems in EAC) and merged the generators into 17 suppliers. Thus, power plants of the same type and owned by the same supplier are merged into one power plant for a node, but we increase the maximum output from that type of power plant.

We also assume that there is one power plant per node, and the primary subsystem classification represents the nodes Table 3.

The EAC has five countries that have different national control centres. These control centres have 17 major subsystems characterised by generation type and large load centres. In this research, we use these major subsystems as the nodal points to capture the region's system appropriately. Therefore, the structure of the EAC nodes will be based on the following:

Kenya has five subsystems, which this research depicts as NN1 to NN5; similarly, Uganda has four subsystems, while Tanzania has three subsystems. Owing to the small size of installed capacity and the interconnection level of Burundi and Rwanda, their subsystems are divided into three and two, respectively.

Generators/Producers are divided between the nodes in each country according to the country's location, as shown in Table 4.

The welfare maximisation problem using a nonlinear programming algorithm is implemented in GAMS to solve the expected welfare and prices. The modelling uses calibrated demand and cost functions in Table 5.

4.1. Model Formulation of the Power Flow

4.1.1. Nomenclature

- n ϵ N: Set of Nodes
- l ϵ T: Lines of Transmission grid

4.1.2. Parameters

- $g_{i,n}$: Capacity of plant type at node n (MWh)
- $C^{c}_{(i,n)}$: Cost of existing conventional power plant at node n($/MWh)

Table 3: Subsystems at the EAC

Country	Subsystems	Node
Kenya	Coastal system	NN1
	Nairobi system	NN2
	Western system	NN3
	Seven folks system	NN4
Uganda	eastern system	NN5
	Kampala system	NN6
	Northern (Karuma) system	NN7
	Eastern (Nalubale) system	NN8
Tanzania	South East system	NN9
	Central (Dodoma) system	NN10
	Northern system	NN11
	Western system	NN12
Burundi	Bujumbura system	NN13
	Rwegura system	NN14
Rwanda	South-western Axis	NN15
	Northern Axis	NN16
	Eastern Axis	NN17

EAC: East Africa community

Table 4: Strategic players by country

Countries	Strategic companies
Kenya	Kengen-Hydro, KenGen-Geoth, Turkana, Aggreko, Tsavo, Iberafrica, Orpower, Rabai, Thika Power, Triumph
Tanzania	TANESCO-Hydro, TANESCO-gas, Songas, IPTL, Symbion, Aggreko, Kilwa, Eskom
Uganda	UEGCL, Bujagali, Aggreko, Jacobsen, KCCL, KML, Electromax, Bugoye
Rwanda	REG-hydro, REG-Dies, REG-Gas
Burundi	REGIDESO

Table 5: EAC demand and cost curves

Inverse demand curves			Marginal cost curves		
Node	Intercept	Slope	Power plants	Intercept	Slope
NN1	440	−0.21	Gen1	46	0.01
NN2	990	−0.47	Gen2	16	0.001
NN3	550	−0.26	Gen3	83	0.01
NN4	330	−0.16	Gen4	5	0.0005
NN5	330	−0.16	Gen5	1	0.001
NN6	440	−0.28	Gen6	5	0.0005
NN7	220	−0.22	Gen7	16	0.01
NN8	550	−0.33	Gen8	16	0.01
NN9	220	−0.11	Gen9	5	0.0005
NN10	550	−0.28	Gen10	5	0.0005
NN11	440	−0.22	Gen11	83	0.01
NN12	550	−0.33	Gen12	16	0.001
NN13	77	−0.05	Gen13	5	0.0005
NN14	33	−0.02	Gen14	5	0.0005
NN15	55	−0.02	Gen15	5	0.0005
NN16	110	−0.04	Gen16	83	0.01
NN17	66	−0.02	Gen17	83	0.01

EAC: East Africa community

- $C_{i,n}$: Cost of other power plants at node n($/MWh)
- d_n: Power consumption by consumers located at node n(MWh)
- $P_n(d_n)$ Inverse demand function at node n
- λ is the reduced form of the energy balance Lagrange multiplier vector
- $\varphi_l^{h\pm}$: Congestion rent depending on the direction of flow
- $\tilde{\omega}_j\ \tilde{\omega}_i$: KKT multipliers for line flow limit and generation capacity
- $PTDF_{l,n}$: Power Transfer Distribution Factor matrix of node n on line l
- T_i: Transmission limit through line l(MWh)
- $g_{i,n}$: Power generated by existing unit in node n(MWh)
- $g_{i,n,max}$: Maximum generation capacity
- *Conventional*: Conventional power plant parameters
- *Ke*, *Tz*, *Br*, *Rw*, *Ug*: Country abbreviations (Kenya, Tanzania, Burundi, Rwanda, Uganda

The total welfare of all the firms as

$$\text{Max}\left\{\begin{array}{l}\sum_{n=1}^{17}\int_0^{d_n^{(Ke,Tz,Br,Rw,Ug)}} P_n(d_n)dq - \sum_{i=1}^{17}\int_0^{g_n^{(Ke,Tz,Br,Rw,Ug)}} \\ \left(C_{(i,n)}^c\right)*\left(g_{i,n}\right)dg_{Conventional}\end{array}\right\} \quad (1)$$

Subject to:

Energy balances

$$\sum_{n=1}^{17} d_n - \sum_{i=1}^{17} g_{i,n,(Conventional)} = 0 \qquad \forall n,\lambda \quad (2)$$

Transmission constraints which are subject to limit of flow (F_{max}) for the line:

$$T_i - \left[\sum_{i=1} PTDF_{1,n}.\sum_n g_{i,n} - \sum_{n=1} PTDF_{1,n}.\sum_n d_n\right] \geq 0 \quad (\varphi_l^+)\forall l \quad (3)$$

$$T_i + \left[\sum_{i=1} PTDF_{1,n}.\sum_n g_{i,n} - \sum_{n=1} PTDF_{1,n}.\sum_n d_n\right] \geq 0 \quad \left(\varphi_l^-\right)\forall l \quad (4)$$

Where F_L=(Ke–Tz), (Ke–Ug), (Tz–Ug), (Tz–Rw), (Tz–Br), (Rw–Br) for cross-border lines and within countries (5)

$d_{n,} g_{i,n} \geq 0$ non-negative constraints (6)

$$g_{i,n} \leq g_{i,n,max} \quad \forall i,n,\tilde{\omega}_i \quad (7)$$

$$F_L \leq F_{Lmax} \ \forall j,\tilde{\omega}_j,n(\text{line flow constraint}) \quad (8)$$

The historical, current, and planned future electricity developments in the East Africa Community make this research relevant, especially in a study involving a congestion management system. The integration of EAC power markets depends on the novel power market design that will ensure a robust internal energy market. Currently, the power markets are not integrated, and in most countries, they are still vertically integrated; hence there is minimal competition in the electricity sector. Indeed, the five countries have embarked on accelerated development of renewables at a large scale which is likely to change the evolvement of the electricity market design for the region.

The modelling follows the system of equations 1 to 8 on the calculation of nodal pricing under DC approximation (Mabea and Macatangay, 2021). The model is first run as unconstrained and constrained using the planned transmission expansion plan and cross-border interconnection for 2030.[1] The sources for the transmission plans are obtained from REG (2019), MoEM (2016), EAPP (2014).

5. SIMULATION RESULTS

The quantification of economic welfare arising from integrating the five power markets under the assumption of no integration and full integration is carried out. The initial simulation of nodal pricing if the electricity markets are not integrated (status quo). This auction assumes that there is no interconnection with neighbouring countries, while in the second case, the allocation of transmission capacities for cross-boundary interconnectors is carried out. The five electricity markets auction is simulated implicitly, and each generator is assumed to bid a share of its production on a spot market in a predefined hour. The simulation is carried out in a GAMS environment.

5.1. Case 1: No Cross-boundary Transmission Network

Simulation in case 1 assumes no integration amongst the electricity markets. Therefore, the total economic welfare results refer to nodal pricing in specific countries. We take this as our starting point in that we introduce, for the 1st-time nodal pricing in every country without cross-border interconnection.

Then under case 2, a full integration model is developed, in which these markets are coupled. The total welfare under no integration is 2.2.m$/h. They are comprised of producer surplus, consumer welfare, and congestion rent. This is the aggregate economic welfare of each country. Table 6 shows the results of *case 1* simulation. The producer surplus is $ 1.7 million, consumer welfare is $ 0.3 million, and the congestion rent within each country is $0.2 million.

Regarding resultant nodal prices, as indicated in Figure 1, the Kenya power system, comprised of Coastal, Nairobi, Western, seven folks, and Eastern systems reflect 108$/MWh,112$/MWh,124$/MWh,292$/MWh and 178$/MWh respectively. Under an unintegrated, the Tanzania power system has the highest nodal prices, especially at the Western system (440$/MWh) and Dodoma node (438$/MWh). On the other hand, the Burundi system has the lowest nodal price amongst the five countries (Bujumbura, 7$MWh and Rwegura, 6$/MWh). Rwanda follows the same trend with low nodal prices in both the Northern and Eastern axis.

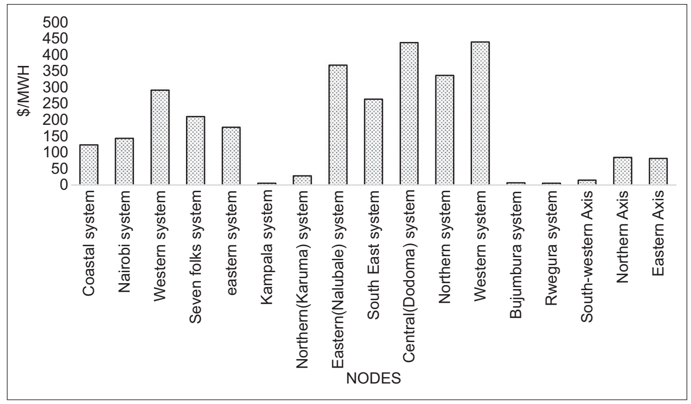
5.2. Case 2: With the Cross-boundary Transmission Network

In this case, the five countries are coupled with cross-boundary transmission lines with a capacity equivalent to the planned future transmission upgrade plans. The starting point of this simulation is to run an unconstrained optimization (if the transmission capacities are limitless) upon simulation; the results of the nodal prices are shown in Figure 2.

Table 6: Total welfare before integration

Welfare	(Million$/hr)
Producer surplus	1.7
Consumer welfare	0.3
Congestion rent	0.2
Total welfare	2.2

Figure 1: Electricity nodal prices (before integration)



If the transmission capacity is unconstrained, the nodal price in the five countries could be uniform, with a value of $67/MWh. A uniform price in the region implies sufficient transmission infrastructure and an absence of congestion in the transmission network. However, upon constraining the power system, nodal prices arise. A comparison between unintegrated and full integration reveals that the nodal price drops by an average of 79% in the Kenya system, with the most considerable drop being experienced in the Western system. On average, Kenya's nodal prices drop by an average drop of $34/MWh.

The highest drop is reflected in the Nalubale system in Uganda. Interestingly, Kampala system's nodal price increased by 69%. The average price drop in the Tanzania electricity nodes is $125/MWh, the highest reduction amongst the five countries. Under no integration, the Burundi and Rwanda nodes showed low nodal prices. However, upon full integration, the prices in Burundi indicate an average price increase of 35$/MWh.

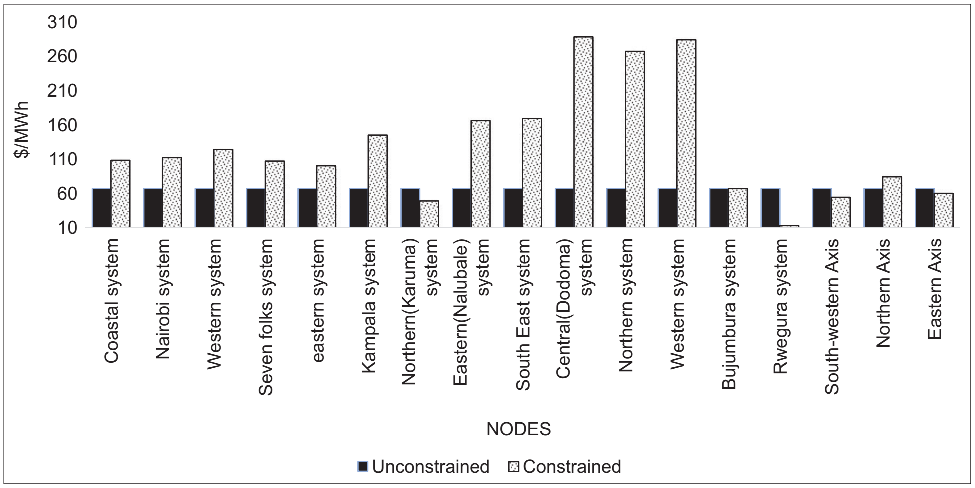
In contrast, Rwanda indicated a minimal price decrease of $12/MWh. The sharp increase in the average prices in Burundi could benefit the producers in the short term. At the same time, consumers absorb the loss in benefits.

The nodes with high prices benefit from nodes with low nodal prices. This means that the consumers at high-cost nodes benefit from the interconnection. Contrariwise, the producers in low-cost nodes benefit from selling to higher-cost nodes. Thus, the resultant economic welfare is increased.

When the interconnectors are constrained, the price splits into nodal prices. The presence of congestion in the power system causes this split. The price differences at the nodes connecting

1. By the year 2030, it is expected that the interconnectors within the EAC could be complete and major upgrades of the internal transmission lines carried out. The data on the transmission lines is obtained from the power master plans for Kenya, Uganda, Tanzania, and Rwanda. Burundi is yet to develop a national power master plan but useful information on the power strategy is available.

Figure 2: Electricity nodal prices (after integration)



each country indicate that; the node connecting Kenya and Uganda power system has a price difference of $21/MWh, while the node connecting the Tanzania power system and Burundi power system has the highest price difference of $275/MWh.

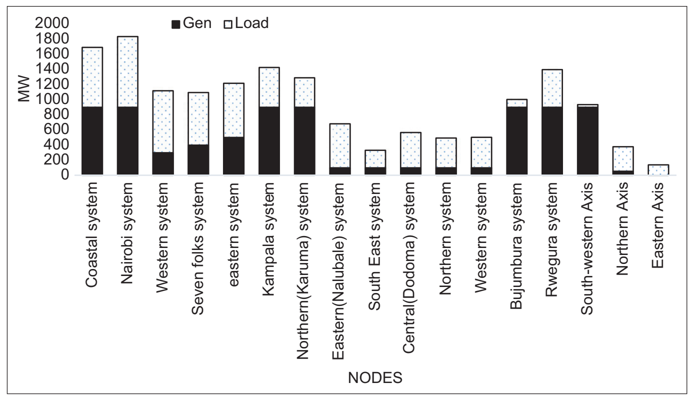
Generally, nodes in Tanzania exhibit higher LMPs compared to other countries. Additionally, the weak transmission network and low-capacity transmission lines introduce congestion in the system, causing the price split among the nodes. However, unlike Tanzania, the generation in Burundi is mainly from hydro sources, so marginal production costs are low. This could be why the prices in Rwanda and Burundi indicate low nodal prices.

Figure 3 compares the quantities of electricity generated and the nodal demand across the EAC power market. The results further indicate that Kenya generates 37% of the total electricity consumed in the region while Uganda generates 24%. Burundi and Rwanda generate 34% and 12%, respectively. Tanzania generates the least at 5% but is the highest importer of electricity among the five countries. The coastal region and Nairobi system generate 30% of the total capacity, while the Eastern system generates 17%. The seven folks system and the Western system generate 13% and 10%, respectively.

The total generation in Uganda is 1900MW. This is composed of the Kampala system that generates 47% of the entire local generation. The Karuma system generates 47%, while the Nalubale system generates 5%. This indicates that most generating facilities are attached to the Karuma and Nalubale system. In Tanzania, each of the four systems generates 25%. However, the power flow from the nodes in Kenya and Burundi meets the remaining demand. As a result, Burundi generates 76% more than the local demand. This excess supply benefits high-cost nodes in Tanzania, while the rest is utilized locally. Similarly, Rwanda generates 48% more than the electricity demand utilized in Uganda.

To answer the first question on the economic welfare of integrating the power markets at the EAC, the research simulated the whole system's economic welfare following the optimal power flow. Consumer surplus is arrived at by summing the product of the difference between the inverse demand intercept and the nodal

Figure 3: Comparison of generation and demand



price times the electricity market demand. On the other hand, the producer's surplus is the power plant's revenue from selling the energy produced at a less marginal cost; the congestion rent less generation cost. We note that only the marginal costs are included in the modelling, and the producer welfare is aggregated for an hour. Our results in Table 7 show that the economic welfare arising from such development could yield 4.8 million/h.

This congestion rent is also arrived at by summing over all the transmission lines (within the country and interconnectors) of the product of the difference in the nodal prices times the net power flow on a given constrained line. The results of the interconnector power flow for the interconnectors assuming the five countries are connected based on the planned transmission investment, as shown in Table 8.

The results of the nodal pricing model show the amount of power flow and direction of power flow, respectively. These results provide interesting information on power exchange in the region, where some countries export while others import. For example, we observe that the connection between Dodoma and Rwegura systems (line 19) is 100% utilized. A similar scenario is observed on line 15 (South East system and Bujumbura system), line 13 (Northern system and Nalubale system), and line 12 (Nalubale System-South East system). The results also indicate that the utilization of another cross-border transmission, line 4 (Western system-Kampala system) and line 10 (Kampala system-Southwestern axis), are both 54% underutilized.

5.1. Power Flow between the Nodes and Interconnectors

Figure 4 indicates congestion rent collected by each node in the five countries. The changes in cross-border led to the reallocation of congestion rent. Within each node, the prices are uniform, but the cross-border congestion rent is indicated in Table 9.

Implementing locational pricing as a way for congestion management will facilitate efficient cross-border trade between these five countries, as opposed to the current bilateral arrangements in which Kenya-Uganda and Tanzania-Kenya engage. This implies that an auction system could be used to allocate the interconnector capacities for the five countries, resulting in high efficiency and increased competition amongst the regional players. However, this requires a well and harmonious coordination of congestion management for the region, and to achieve this, the region must develop a regional framework and guidelines to oversee the implementation.

As indicated in Table 9, the highest congestion rent is experienced in the Uganda-Rwanda interconnector. Nevertheless, the lowest congestion rent is paid for the power trade between Tanzania-Rwanda interconnectors. The congestion rent between Kenya and Uganda is $17,318, while that between Kenya-Tanzania is $12,097. The congestion rent accruing from Uganda-Rwanda ($76,159) indicates the level of power flow constraint in this link. This line is 100% utilised, limiting any extra flow to meet the demand in the sink node or low-price node. We see a similar case between the line interconnecting Rwanda-Burundi in which the congestion rent amounts to $30,635.

The high congestion rent indicates substantial price differences between the nodes adjacent to each other and the power flows between the nodes. The product of the difference in nodal prices and the power flow between them gives rise to the congestion rent or payment to the transmission operator. The results further indicate the lines which need upgrading to allow for higher power flow between the countries and provide a robust power market.

Price signals indicate more congestion in the central part of Tanzania, and it could cost less for Tanzania to import than to produce electricity. In a full nodal pricing model, the congestion rent is collected by each country exporting the electricity. The model indicates that Kenya could collect the congestion rent from Tanzania and Uganda. Rwanda could collect the congestion rent from Burundi and Uganda. This model, therefore, finds out that Uganda is a net importer, which is why the congestion rent is high.

The physical power exchange given by the full nodal pricing solution model indicates that the power flows go from Kenya to Tanzania, Kenya to Uganda and Uganda to Tanzania. Figure 5 shows a simplified physical electricity flow for a full nodal pricing model.

The physical flows indicate the increased energy movements from one country to another if the markets are coupled, and the interconnectors are built. For example, the trade between Kenya and Uganda is 370MW. In contrast, the lowest trade occurs between Tanzania to Rwanda and Tanzania to Burundi, with a 100MW capacity.

Table 7: Total welfare after integration

	Welfare (m$/h)
Producers surplus	3.6
Consumer surplus	1.1
Congestion rent	0.1
Total welfare	4.8

Table 8: Lines and flows

Line	From	TO	Flow (MW)	Transmission (MW)
1	NN2	NN1	50	140
2	NN3	NN2	16	140
3	NN4	NN3	85	140
4	**NN3**	**NN6**	**588**	**1500**
5	NN4	NN5	211	140
6	NN5	NN1	59	140
7	**NN5**	**NN15**	**370**	**800**
8	NN6	NN7	300	140
9	NN8	NN6	271	140
10	**NN6**	**NN15**	**186**	**400**
11	NN8	NN7	211	140
12	**NN8**	**NN9**	**100**	**100**
13	**NN11**	**NN8**	**100**	**100**
14	NN10	NN9	67	140
15	**NN9**	**NN13**	**300**	**300**
16	NN11	NN13	197	140
17	NN12	NN13	300	140
18	NN12	NN11	3	140
19	**NN10**	**NN14**	**300**	**300**
20	NN14	NN15	8	140
21	NN17	NN14	110	140
22	NN16	NN15	300	140
23	NN17	NN16	30	140

Bold lines indicate the cross-border lines

Table 9: Cross-border congestion rent (in $)

To	Kenya	Tanzania	Burundi	Rwanda	Uganda
From					
Kenya	-	12,097	0	0	17,318
Tanzania	0	-	9,815	271	16,976
Burundi	-	0	-	0	-
Rwanda	0	0	30,635	-	76,159
Uganda	0	0	-	0	-

Figure 4: Congestion rent for the whole system

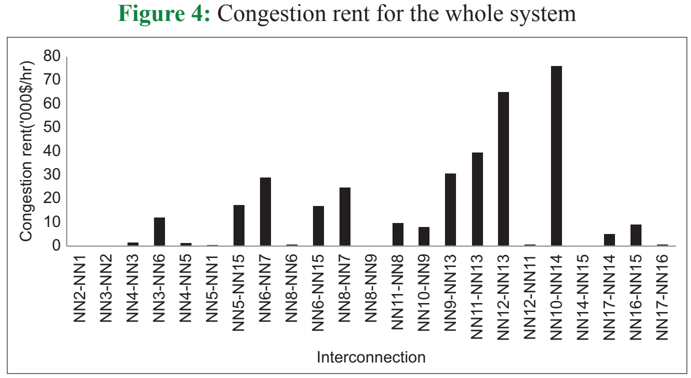


Figure 5 and Table 10 show the matrix of power exchange between countries. Again, Kenya stands out as a net exporter, owing to some nodes having lower locational prices and high supply, while Uganda benefits from low-cost nodes in Rwanda and Tanzania.

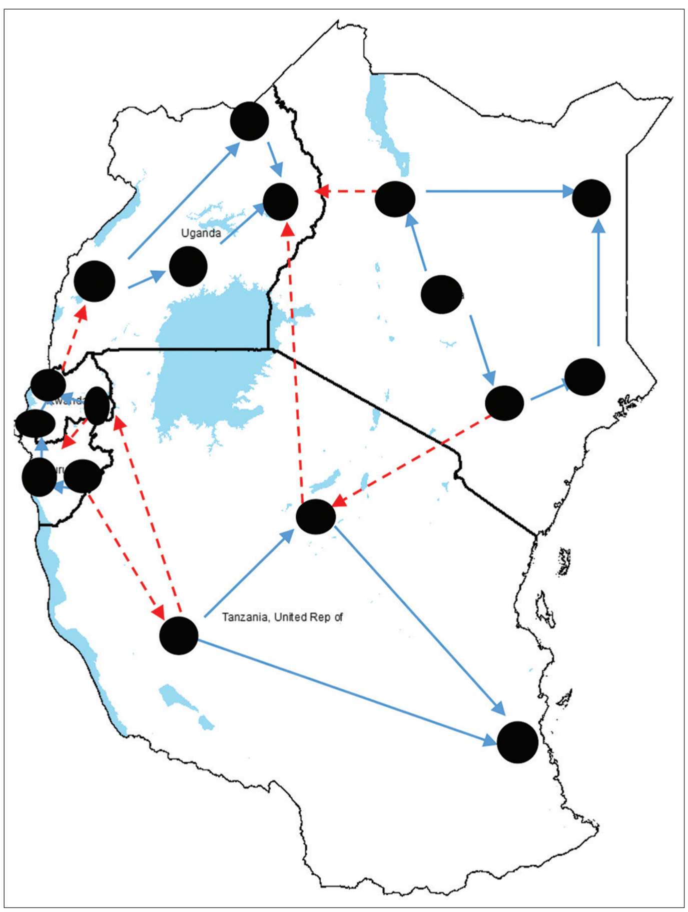
Although Rwanda and Burundi export, the capacity is low (100MW) compared to other interconnectors due to these countries' low generation capacity. On the other hand, the power trade between Kenya and Tanzania has the highest value of 588MW because of the assumed high transmission capacity. This indicates that infrastructure development is a precondition for efficient electricity market integration in the region. This integration realizes 402MW net imports for Tanzania and 958MW net export for Kenya. This competitive effect arising from full integration determines the increase in consumer surplus and congestion rents.

Table 10: Constraints on the EAC system

Boundary	Country affected	Max rating (MW)
4	Tanzania imports from Kenya	1500
7	Uganda imports from Kenya	800
10	Uganda imports from Tanzania	400
12	Tanzania exports to Rwanda	100
13	Burundi exports to Tanzania	100
15	Burundi imports from Rwanda	300
19	Rwanda exports to Uganda	300

EAC: East Africa community

Figure 5: Simplified version of the transmission system and power flow in East Africa community
Red dotted lines indicate the cross-border lines



5.2. Comparison of Case 1 and Case 2

Besides Kampala, Karuma, Bujumbura, Rwegura and southwest axis systems, other systems show a percentage decrease in price because of full integration. Figure 6 indicates that Nalubale experiences a 100% drop in nodal prices followed by an 82% drop at the western system for the unintegrated case. Market integration maximizes the use of available interconnection capacities, allowing more power from other countries to flow into the local market. This drop justifies the need to upgrade the existing infrastructure not only to increase energy access in these countries. In the Kenya power system, it is shown that the coastal system, Nairobi system, Western system, and the Eastern system have a drop in nodal prices amounting to 8, 16, 83, 51, and 38%, respectively. In the Uganda power system, Nalubale indicates a price drop of 100. Tanzania's, South East, Dodoma, and Western system show a price drop of 47, 74, and 35%, respectively, while Rwanda indicates the lowest price drop in the Northern axis (1%) and Eastern axis (11%).

The Uganda electricity nodal prices turned out to be higher than the assumed full integrated model. This hefty price differential could be attributed to high demand but an insufficient network.

Figure 7 shows welfare changes because of introducing locational pricing and integrating the electricity markets. Summing the

Figure 6: Change in nodal prices per node

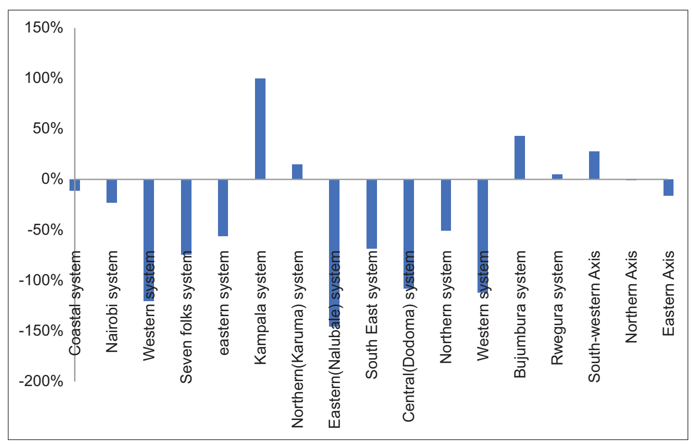
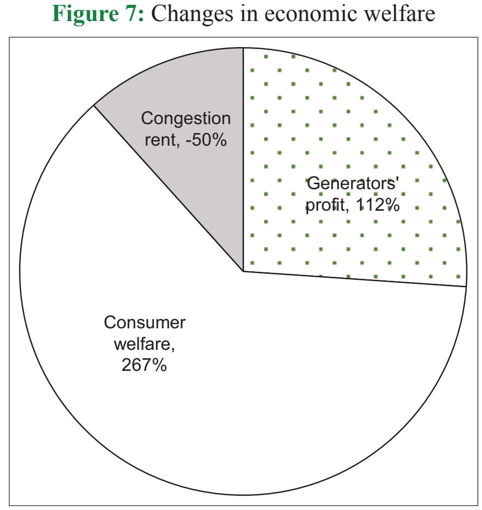


Figure 7: Changes in economic welfare



impact of full integration, it emerges that the overall net welfare increases by 118%, comprised of a 50% drop in congestion rent, a 112% increase in generator's profit, and a 267% increase in consumer welfare. Thus, electricity market integration contributes significantly to increased economic welfare for the EAC markets.

6. CONCLUSION

This research aimed to simulate the impact on East Africa's electricity market by introducing locational marginal pricing to increase efficiency, competition and cross-border trade among the five countries. Electricity market integration maximises the utilisation of interconnector capacities between countries; hence electricity flows and elimination of arbitrage are feasible under a novel auction mechanism. The simulations of two cases of the EAC market, the unintegrated case, which is based on the current state of the power markets and case two, which tends to introduce full market integration under nodal pricing, reveal a potential increase in total economic welfare in these countries.

In the first case, the net welfare for the unintegrated electricity market is 2.2Million$/h. Under case two, the net welfare gain for full integration is 4.8 million/h. If the electricity markets are coupled, the welfare gain could be $ 2.6 million/h. This increase in social welfare by introducing full integration at the EAC market proves that the introduction of locational pricing and integrating these markets is fundamental. Furthermore, this simulation, which employs a robust optimal power flow under nodal pricing using GAMS software, has the merit of proving a good measure of locational prices-detailed economic welfare gains that could be attained by the market participant when the markets are fully integrated.

When the markets have limited integration, the actual nodal prices are higher than the results of a simulation in which the markets are fully integrated (Joachim et al., 2020). The prices in the coastal system, Nairobi and the western systems decrease by 8, 16 and 83%, respectively. These are the systems in Kenya. In Uganda, the Nalubale system shows a decrease of 100%. In contrast, in the Tanzania system, South East, Dodoma, and Western systems showed a price decrease of 47, 35 and 77%, respectively. It turns out that the prices in Burundi and Rwanda did not show any significant decline. This could be due to a combination of factors such as a high level of hydropower plants and low demand.

Although we find that integrating these power markets is beneficial, its realisation must be preceded by significant regional institutionalisation and liberalisation. A deliberate harmonisation of the necessary laws and regulations must accompany this process. This research could be extended to consider the cost of harmonisation and integration implementation. Another potential research area could be to test the convergence of the nodal prices in the region once the market has been established.

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