Competition and Regulatory Reform in the Turkish Electricity Industry[1]

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Introduction

Turkey has initiated a major overhaul of the legal and regulatory framework surrounding the electricity industry. The reform program entails liberalisation as well as a radical restructuring of the industry, that is, its generation, transmission and distribution segments, including wholesale and retail activities. The purpose of this paper is to review and assess the new regulatory regime, identify the main competition-related challenges that the industry is likely to face and discuss future prospects. The paper will attempt to evaluate the reform process in light of the regulatory framework established at the level of the European Union (EU) and the current debate on the proposals towards its amendment.

The paper is organised as follows. The next section reviews the physical peculiarities of the electricity industry and discusses how they have shaped the evolution of its industrial organisation. Section II presents an overview of regulatory reform in the EU, the 1996 directive, and the recent proposals for amendment advanced by the European Commission. The discussion is organised around five main headings, namely market opening, unbundling, third party access, public service obligations and regulation. Section III discusses the pre-and post-reform structure of the electricity industry in Turkey and the main features of the new regulatory regime under the five headings described above. Section IV identifies the main challenges that the industry is likely to face in the process of developing effective competition. A final section discusses possible competition-enhancing solutions.

I. Characteristics and evolution of the industry

The electricity industry consists of three main interrelated segments. Electricity is *generated* in plants using the flow of water, the burning of fossil fuels (thermal), the power of wind, sun or earth (geothermal), or nuclear fission. *Distribution* refers to the supply of electricity to residences or businesses through lower voltage wires and transformers. The *transmission* of electricity refers to the actual transportation of higher voltage electricity between generation plants and distribution facilities, the interconnection of geographically dispersed generation plants, their scheduling, and orderly dispatch. The operation and commercial principles of related wholesale and retail supply activities are quite similar with both involving metering, computing and billing. An important distinction is that the wholesale trade business is carried out

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mostly at the transmission level at a larger scale, while the retail trade business is carried out through the distribution system at the end-customer level with both smaller business and household users.

Several characteristics of the electricity industry distinguish it from other industries. There is no economical way to store electricity. That implies that the demand for and supply for electricity have to be balanced almost continuously in real time. In addition, demand for electricity varies hourly and daily as well as across months and seasons. Consumers can obtain electricity as long as they are connected to the network as there is no cost-effective way of establishing physical contact between specific consumers and generators. Rather, electricity from generating plants flows to a common pool and is retrieved by consumers from that pool. In the short run, the price elasticity of demand is very low. Generating plants have rigid, non-flexible capacity constraints so that supply is relatively inelastic especially at peak demand times. In addition, several physical constraints, such as voltage, have to be met. The most binding constraint affecting system operations is the limitation on the power carrying capacities of lines and transformers. Congestion resulting from this constraint can in principle so severely limit system operation that it could impede the transfer of production from a least-cost plant to a load even though both parties would wish to make the requisite sales agreement. Hence balancing supply and demand requires that production of different plants be coordinated and scheduled, taking the existing capacity of lines and transformers into account. Generators need to be called upon for the system to be able to respond to changes in demand or supply. They need to hold a minimum level of reserve capacity to keep the probability of system failure below an acceptable threshold. Failure at one point in the network (say, failure of a generation plant) can have serious repercussions on the whole network if not managed properly. So there are strong externalities in terms of network security.

The need to coordinate generation and supply almost on a minute-by-minute basis provides incentives to vertically integrate these two activities. Indeed, in most countries electricity services historically have been supplied through vertically integrated enterprises encompassing generation, transmission and distribution activities. In Europe, such enterprises have been organised as monopolies under public ownership. In the US, the predominant form of industrial organisation has been privately-owned but regulated franchises with monopoly rights to serve specific geographic regions.

Electricity transmission and distribution involve large sunk capital costs with strong economies of scale (in the sense that duplication of lines would be economically wasteful) so there is little scope for competition in these segments of the industry. By contrast, electricity generation is now regarded as potentially competitive, especially with the advent of the smaller-scale combined cycle gas turbine (CCGT) technology. Generation is generally regarded to exhibit increasing returns of scale at low levels of production and constant returns to scale otherwise (Armstrong, Cowan and Vickers 1994, p. 282. Armstrong et. al. report Joskow and Schmalensee's estimate of minimum efficient scale for fossil-based plants at 400 MW capacity.)

In the last 10-15 years, the predominant view has evolved to favour the introduction of competition into generation and retail supply activities. Some countries (such as

Chile and the UK) were pioneers but the wave of liberalisation has been widespread, covering developing and developed economies alike.

II. Regulatory reform in the EU

The European Commission's effort to liberalise electricity markets in the EU was primarily driven by the quest for a single market but was met with resistance by many national governments.[2] In 1991, the Commission came up with a proposal to allow third party access within the electricity markets of all member states. The Council of Ministers rejected that proposal. By 1993, the concept of negotiated (as opposed to full or regulated) third party access was presented as one of the options being discussed. In 1994, France introduced the single buyer model as an alternative to negotiated third party access. Eventually, in 1996, an agreement was reached on a timetable for liberalisation and each member state was given a choice between the three alternatives for access. The agreement culminated in the European Parliament's Electricity Directive.[3]

Liberalisation of the electricity sector was strongly supported by the Competition Directorate General of the EC (the former DG IV) through threats by DG Competition that otherwise there would be tougher action on the basis of Articles 81 and 82 (Pollitt, 1999 p. 50).

The Electricity Directive of 1996

The basic idea behind the Electricity Directive is to introduce competition to the potentially competitive segments of the electricity industry (i.e. generation and retail supply) and to regulate transmission and distribution, which retain natural monopoly characteristics. The Directive can be examined under four headings.

Market opening

On the demand side, the Directive envisaged minimum market opening on the basis of consumers designated to have freedom to contract their consumption of electricity (so-called 'eligible customers'). Each member state was envisaged to "open" a given and increasing percentage of its market over the next six years. That percentage was to be calculated as the share in overall Community consumption of final consumers consuming more than 40 GWh per year, with the threshold to be reduced to 20 GWh in the second step (within 3 years) and 9 GWh in the third step (within 6 years). Those thresholds have been estimated to correspond to market share openings equal to 27%, 28% and 33% respectively to be reached in 1999, 2000 and 2003.[4] Each member state was to designate its own set of eligible customers but consumers with

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[2] This section builds on Pollitt (1999) and Newberry (2002a, c).
[3] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 Concerning Common Rules for the Internal Market in Electricity. The text of the Directive, an accompanying explanatory memorandum as well as proposed amendments (discussed below) can be found at http://europa.eu.int/comm/energy/en/elec_single_market/index_en.html.
[4] Guide to the Elecricity Directive http://europa.eu.int/comm/energy/en/elec_single_market/memor.htm

more than 100GWh consumption were to be definitely included in that designation.In order to address problems that might arise if the degree of market opening differed across states, the Directive included provisions for *reciprocity:* a member state has the right to refuse access for companies from states that have not liberalised to an equal extent.

On the supply side, the Directive provided for two mechanisms for the development of new capacity in generation, both aiming at introducing competition:

- Authorisation: Companies offer to build new power plants under an open and impartial procedure that decides whether they should go ahead
- Tendering: An authority decides what new capacity is required. It solicits tenders, which are then assessed through an impartial procedure

Unbundling

In order to prevent discrimination, cross subsidisation and distortion of competition, the Directive obliged integrated operators to separate the management of the generation, transmission, distribution and non-electricity activities and to keep separate accounts for each. In order to ensure non-discrimination, an independent authority for dispute settlement was also envisaged.

Each member state was required to specify a *transmission system operator* (TSO) whose task was to ensure dispatch of plant according to fair and transparent rules that do not favour plants owned by the same company as the TSO. The unbundling of the TSO was deemed to be crucial (management, legal or ownership unbundling).

Regarding distribution, system operation in distribution was to be under the same non-discriminatory basis as transmission.

Third party access

One of the main objectives of the Directive was to enable independent generators access to the transmission and distribution networks in order to supply final customers. The Directive prescribed three types of access arrangements. Member countries could also choose hybrid arrangements:

- Negotiated Third Party Access (nTPA): Consumers and producers contract directly with each other and then negotiate with the transmission and distribution companies for access to the network.
- Regulated Third party Access (rTPA): Access prices are not negotiated but rather are published by the regulator.
- Single Buyer Model (SBM): There is a single wholesale buyer of electricity. There can be competition in generation, but retail competition is limited. Eligible consumers that are not tied to a specific distributor/retailer can still contract with producers. The single buyer pays the producer its regulated sales price minus network charges. The producer can then compensate the consumer so that the consumption prices become equal to the contract price.

Public service obligations (PSO)

The Directive also recognises that some objectives deemed desirable from a social point of view may not be achieved through unfettered competition. To achieve these objectives, the Directive provided that member states may impose such obligations to electricity undertakings. The objectives mentioned in the Directive were security (including security of supply), regularity, quality, price and environmental protection. The obligations would be defined by member states.

Progress with implementation and proposed amendments

In March 2001, the European Commission issued a Communication assessing the progress in the development of the internal market for electricity and the effects of the implementation of the 1996 Directive (EC 2001a) and proposed a series of amendments (EC 2001b). The Communication underlined the importance of the full opening of energy markets in improving Europe's competitiveness. According to the Commission, the effects of market opening were positive. However, it was also stated that in order to complete the internal market, further measures were necessary. The key points made were as follows.

By 2000, average market openness in the Community had reached 66 percent, greater than thresholds established in the Directive. However, progress was very uneven across countries; there were countries with full market opening and others where market opening was limited to 30 percent. It also was stated that the reciprocity provisions of the Directive proved unable to address problems of unevenness in the competitive environments between member states. There was a concern that if this situation of unevenness were maintained over a longer period, a level playing field would not develop within the internal market.

Regarding access, 14 member states had chosen rTPA. Only Germany had selected the nTPA regime. Italy and Portugal had chosen SBM for captive (i.e. non-eligible) customers and rTPA for eligible customers. Most member states had chosen the authorisation as the procedure to elicit additions to generation capacity. However, the ultimate goal of non-discriminatory access to the network was not fully achieved. Absence of standard and published third party access tariffs was seen as a significant barrier to entry. Another barrier was the absence of effective unbundling in member states. Germany and France chose management unbundling; 7 countries chose legal unbundling and 5 countries chose ownership unbundling. Hence effective access required further strengthening of unbundling.

The Communication underlined the benefits of progress in competition. Prices for industrial users had come down in all member states, but larger price decreases occurred in countries where liberalisation was 100%. Reductions also have occurred in household prices, though to a lesser extent overall than prices for industrial users. Larger reductions had taken place in countries where customers are free to change suppliers, and where this is de facto easy to do.

The Communication also raised concerns about the pace of cross-border trade. It stated: "The objective of the Electricity and Gas Directives is the creation of one truly integrated single market, not fifteen more or less liberalised but largely national markets" (p. 9). It underlined that even though there was an overall increase in the number of customers having switched suppliers, most customers tended to opt for national suppliers. Overall, cross-border trade was limited. To expand cross-border trade, it was necessary to develop appropriate rules with respect to the pricing of this trade, to develop rules for the allocation and management of scarce interconnection capacity, and where necessary increase such capacity.

In short, the Commission indicated that there were "several weaknesses in the current legal framework which needed to be remedied if a fully operational internal market for gas and electricity is to be achieved" (European Commission 2001a, p. 6). On the basis of these findings, the Commission developed proposals to amend the Directive (European Commission 2001b). The most important proposed amendments were as follows:

- *Market opening:* Allow all electricity customers freedom to choose suppliers (end domestic customer franchise monopoly) by January 1, 2005. This was called the quantitative proposal.
- *Unbundling:* Strengthen unbundling to legal and functional separation of transmission from generation (hence management separation alone was no longer sufficient, and ownership separation is now appropriately promoted as a form of unbundling stronger than legal separation).
- *Access*: Strengthen access by requiring rTPA with published tariffs. Do not permit SBM.
- *Public service obligations (PSO)*: Explicit mention of obligation that member states should ensure universal service, defined as "supply of high quality of electricity to all customers in their territory", as well as protection of vulnerable customers and final consumers' rights.
- *Regulation*: Establish an independent regulatory authority to approve tariffs and conditions for access to transmission and distribution networks *ex-ante* and to monitor and report to the Commission on the state of the electricity markets (particularly regarding supply-demand balances).

The proposals did not prescribe a specific model for the organisation of wholesale activities. Some of the proposals were initially met with opposition. In particular, Germany opposed the requirement for an independent regulator and ex-ante regulation of access prices and conditions (Newbery, 2002). The principles of non-discriminatory access to the network, based on transparent and published tariffs, and the establishment of independent regulators were adopted by the Barcelona European Council in March 2002 (EC 2002a). The Council also drew attention to the need to take measures on PSO, in particular with respect to remote areas and vulnerable groups. During the November 2002 meeting of the Energy Ministers, an agreement was reached that full market opening would be achieved in 2004 for non-household customers and 2007 for household customers (EC 2002b). Unbundling is intended to be achieved by July 2004 for transmission and 2007 for distribution. The proposed amendments were finally adopted in June 2003. [5]

[5] See "Directive 2003/54/EC of the European parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC". The new Directive is available at http://europa.eu.int/comm/energy/electricity/legislation/index_en.htm

III. The current structure of the Turkish electricity industry

Background

As was the case in many European countries until recently, the Turkish electricity industry was dominated by a state-owned vertically integrated company, TEK.[6] In 1993 in an attempt to prepare TEK for privatisation, it was separated into the Turkish Electricity and Transmission Company (TEAS) and the Turkish Electricity Distribution Company (TEDAS).

Beginning in the 1980s, the government sought to attract private participation into the industry. This was motivated both by a general disposition towards the private sector that emerged in the 1980s and fiscal constraints, purportedly to ease the investment load on the general budget. However, this effort was constrained by the constitutional regime that interpreted the provision of electricity as a public service that needed to be supplied by the government. Instead of responding directly by seeking to remove this constitutional challenge, governments of the 1980s and 1990s chose to create shortcuts[7] through various private sector participation models short of privatisation. The first law setting up a framework for private participation in electricity was enacted in 1984 (Law No. 3096).[8] This Law forms the legal basis for private participation through Build Operate and Transfer (BOT) contracts for new generation facilities, Transfer of Operating Rights (TOOR) contracts for existing generation and distribution assets, and the autoproducer system for companies to produce their own electricity. Under a BOT concession, a private company would build and operate a plant for up to 99 years (subsequently reduced to 49 years) and then transfer it to the state at no cost.[9] Under a TOOR, the private enterprise would operate (and rehabilitate where necessary) an existing government-owned facility through a lease-type arrangement. In 1994, Law No. 3996 and Implementing Decree 5907 were enacted to enhance the attractiveness of BOT projects by authorising the granting of guarantees by the Undersecretariat of Treasury and providing tax exemptions (as well as extending the purview of the model to other public services such as water & wastewater, transport and communications).[10] An additional law for private sector participation in the construction and operation of new thermal power plants through a licensing system rather than concession award, the Build-Operate-Own (BOO) Law, was enacted in 1997 (Law No. 4283), again with guarantees provided by Treasury. Under the BOO model, investors retain ownership of the facility at the end of the contract period.

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[6] For background on the Turkish electricity sector see OECD (2002), Zenginobuz and Oğur (2000), and Kulalı (1997).
[7] OECD (2002) calls this “policy work-arounds”.
[8] It is entitled ‘Law concerning the authorisation of enterprises other than Turkish Electricity Authority for the production, transmission, distribution and trade of electricity’.
[9] In practice, most BOT contracts have been for 20 years.
[10] Law 3996 is entitled ‘Law for certain investments and services to be carried out under the Build-Operate-Transfer Model’. The scope of the BOT model under this new Law (Article 2) appears to limit its application to greenfield projects, requiring TOOR projects for existing assets to be governed by the Privatisation Law (Law No. 4046, also dated 1994). The electricity sector was removed from the domain of Law 3996 in 1994 (through Law No. 4047) but was reinstated in 1999 (through Law No. 4493).

A typical BOT, BOO or TOOR generation contract, signed between the private party and TEAS or TEDAS, includes exclusive "take or pay" obligations with fixed quantities and prices (or price formulas) over 15-30 years. Hence it does not provide a framework for competition *in the market* but only potentially for competition *for the market* if the contracts are granted through a competitive process in which lowest cost proposals are accepted. The main benefits in principle of such private sector participation contracts arise from transferring those risks to the private sector that it is best able to manage (including most commercial risk during the operating phase), from accessing strong and effective private sector commercial and managerial skills for reduced operational costs and improved service quality, and from spurring adoption of innovation at both design and implementation phases of projects. However, such efficiency-related benefits are only likely to arise from competitively-tendered projects. Unfortunately, there was no rigorous framework in place to ensure implementation of competitive tendering. On the contrary, under the Turkish BOT model, there was no requirement for prequalification, nor for a competitive open tender, nor even for a closed tender (the 'method of sealed bid from selected companies' merely require at least 3 interested companies to submit their offers). Unsolicited bids could be brought forward and negotiated solely on the basis of an investor-completed feasibility study (through 'the method of negotiation'). Compounding these problems, under the Turkish BOT, BOO and TOOR generation models, the government has retained most commercial risks while providing the private sector with substantial rewards. Under these contracts, Treasury has provided guarantees to cover critical commercial take-or-pay payment obligations such as minimum electricity generation levels and minimum quantities of gas in power station gas purchase contracts at associated pre-determined prices in USD over the life of the contracts.[11] Although the fixed price nature of the contracts creates incentives for cost efficiencies, the contracts preclude any possibility for making consumers share in any efficiency gains: all cost savings are appropriated by the generator. In addition to the relatively high electricity cost from many of these projects, the BOT and TOOR contracts are heavily front-end loaded with higher capacity charges in the first years of operation to allow for early recovery of investment costs (OECD 2002). As will be discussed below, the current structure of these contracts acts as a major barrier to the development of competition in the generation sector.[12]

There have been a large number of BOT proposals or projects that have not been completed.[13] Initially the main constraint was the prevailing interpretation of the Constitution, namely the fact that even though Law No. 3996 stated that BOT contracts would be subject to private law, the Constitutional Court decided that electricity was a public service and therefore these BOTs were considered as concessions under public administrative law. This meant that the development and

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[11] The take-or-pay element of the contracted gas varies from contract to contract but on average is 80%, implying for instance that in 2005 some 33 BCM of gas must be purchased whether it is needed or not. ECA (2002).

[12] While there is general agreement now that these contracts are not in the best public interest, it is still not clear why they were awarded in the first place. One explanation, mentioned above, argues that the government saw an urgent need to attract private investors (both because of fiscal constraints and because it saw that as a means of reducing state dominance) and had to pay high risk premiums because of macroeconomic uncertainty and, in general, weak protection of property rights. Other argue that that view is naïve and point to lobbying and capture by investor groups, and weaknesses in checks and balances.

[13] The evolution of BOT and TOOR projects in generation and distribution is further discussed below.

eventual completion of a BOT contract required intervention and approval from a multitude of government agencies, including the Ministry of Energy and Natural Resources (MENR), the High Planning Council (referred to by its Turkish initials, YPK), the State Planning Organization (SPO), and the Treasury. In addition, the public law character of the contract meant that investors did not have recourse to international arbitration and contracts had to be reviewed by Danıştay, the Council of State, which was a lengthy process.

In August 1999, a constitutional amendment opened the way for privatisation in the electricity sector, for the application of private law to contracts, and for limits to the scope and duration of the Danıştay review.[14] While the constitutional amendment (and the subsequent Law No. 4501 of January 2000 which implemented these changes) simplified the legal framework for private participation, the new obstacle to the development of BOT contracts was the unwillingness of the Treasury to provide new guarantees, in light of the implied contingent liabilities.

By the end of the 1990s, it became clear that quasi-privatisation with Treasury guarantees was not going to be feasible given the rapidly deteriorating fiscal stance. In addition, there was a wider appreciation that these types of contracts which locked generation companies into long-term exclusive sale agreements with pre-determined, fixed prices did not serve the overall objective of developing competition in electricity markets. There was already work undertaken in several government agencies (e.g. MENR, SPO, the Treasury) for the design of a competitive electricity sector regulated through an independent agency. In 2001, Law No. 4628 (the Electricity Market Law, EML) provided a new and radically different legal framework for the design of electricity markets, and established a new independent Energy Market Regulatory Authority (EMRA).

The current model

The main drivers for liberalisation in Turkey were very different form those that preoccupied the European Union or leaders of electricity liberalisation such as the UK. The EU was primarily concerned with creating an internal market. Countries such as the UK were motivated by inefficiency of public enterprises (the ownership dimension) and the opportunities generated by technological changes that made competition possible in generation (the market structure dimension).[15] In Turkey, the main driver as well as the public justification of private participation under the pre-2001 regime and of liberalisation under the new regulatory regime was rapid growth in demand combined with the inability of the government to meet that demand through public investments or Treasury-guaranteed private investments, given the deteriorating fiscal situation.

Still, the degree of competition envisaged in the new framework is more advanced than the EU Directive of 1996. In most respects it is compatible (if not more competitive) than the proposed amendments to the Directive that are currently under discussion. As will be discussed in the next section, the main challenge of the Turkish

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[14] Law No 4446 Regarding Amendments on Certain Articles of the Constitution of the Republic of Turkey, published in the Official Gazette August 14, 1999.

[15] Many authors also draw attention to the Conservative Party's overall –ideological—dislike of government intervention in the economy (e.g. Newbery 2001).

case is that the competitive framework notwithstanding, actual development of competition is likely to take some time given the legacy of Turkey's recent past: the current structure of ownership (dominance of state-owned assets in generation) and even more problematically the uncompetitive, tied nature of the contracts governing the privately-operated assets.

The new Turkish regime as contained in the primary legislation and implementing regulations puts emphasis on competition in ordering the market. The main principles of the EML, and their status vis a vis the 1996 Directive are as follows.

Market opening

On the demand side, customers that consume more than 9 GWh per annum are designated as eligible consumers free to choose their suppliers. This meets the targets of the Directive. The main operational difficulty in market opening is estimating the number of expected eligible customers, as higher numbers mean more measuring, tele-metering, and computing hardware and software, implying larger investment expenditures requirements by wholesale and retail companies. These must then be reflected in consumer tariffs. As of May 2003, the estimated eligible customers above 9 GWh per annum are 103 at the transmission level and 507 at the distribution level, accounting for 13.5% of overall consumption (Sevaioğlu, n.d.).[16] However, this number is likely to increase as additional industrial users are expected to enrol as eligible customers through demand aggregation with users having similar demand characteristics.

On the supply side, the authorisation-type licensing framework established in the new regime also appears to be fully compatible with the Directive. It provides entry opportunities into generation (Independent Power Producers or IPPs, and autoproducers who can sell up to a maximum of 20% of their annual production to consumers other than their shareholders), wholesale trade, distribution, and retail trade, import and export of electricity. Distribution companies may also operate as retail sales companies in their regions by obtaining a retail sales license and may import electricity if allowed in their license. Distribution companies may establish joint ventures with generation companies or set up generation units (not exceeding market share of 20%). Transmission remains as a state monopoly but private generators can establish private direct transmission lines. The only limitation is that granting of generation licenses by EMRA is conditional on no congestion in the transmission-distribution link connecting the new plant to the grid or directly to customers. According to EMRA, congestion in the transmission network is most likely to be resolved through some type of auctions among the companies that would benefit from the transmission investments (Sevaioğlu, n.d.)

Unbundling

TEAS has been further unbundled into EUAS (generation), TETAS (wholesale trading and contracting) and TEIAS (transmission), each organised as a separate legal entity. Hence the degree of unbundling between generation, transmission and distribution envisaged and carried out under the EML goes beyond the minimum

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[16] Data provided by Prof. Dr. Osman Sevaioğlu, Member of the Board, EMRA, May 11, 2003.

Directive requirements of management separation and unbundling of accounts. The secondary legislation regulating these activities are under preparation by EMRA.

Under the new structure, EUAS will take over, operate or close down the state's existing power plants that are not transferred to the private sector. TETAS is created to carry out wholesale operations. It will take over all existing energy sale and purchase agreements from TEAS and TEDAS (distribution). TEIAS is responsible for transmission assets, for system operation and maintenance, planning of new transmission investments and building of new transmission facilities, and critically for the Balancing and Settlement Procedure that will balance the power transactions among parties, both physically and financially. Hence in the words of the Directive, TEIAS is the TSO. All transmission facilities owned and/or operated by other companies are envisaged to be transferred to TEIAS according to the EML. In line with this requirement, the transmission facilities that previously had been awarded to private investors through concessions to the two companies Kepez Elektrik (Antalya region) and Cukorova Elektrik or Ceas (Adana, Mersin, Hatay and Osmaniye regions) were seized by the Ministry of Energy[17] and handed over to TEIAS in June 2003, as the companies had failed to hand them over by February 2003 as required.[18]

Third party access

EML requires the rTPA regime for access to the transmission and distribution. An independent regulatory authority is created which, among other things (see below), will carry out the function of dispute settlement between parties.

Market design

As highlighted in Figure 1, at the heart of the new regime is a bilateral contracts market where generation companies contract with wholesale trade companies (TETAS and any eventual new entrants), distribution companies, any new independent retail companies, and eligible customers.[19] On the generation side, EUAS will likely be split into a hydro generator (holding all state-owned hydro plants transferred from DSI, the Directorate General of State Water Works) and a small number of affiliate portfolio generation companies (holding the state-owned thermal plants and mobile plant contracts). EUAS also will hold the physical assets associated with any TOOR (generation) contracts. Existing and new autoproducers (generation by industrial facilities for own use) will compete with respect to their excess capacity with other generators for contracts with distribution companies, independent retailers and directly with eligible consumers. As illustrated, the dominant state-owned wholesaler TETAS is also the holder of all previous BOO, BOT and TOOR

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[17] EML art. 2.b states that TEIAS is to take over all "publicly owned" transmission facilities. A Communique issued by EMRA in November 2002 envisaged the transfer of all transmission assets to TEIAS by December 31, 2002. This deadline could be moved by a month by the decision of the Board of EMRA (Communiqué on the amendments of contracts of undertakings active in more than one market and on transfer of transmission activities and activities which are to be withdrawn from). There is an apparent disagreement between CEAS and the government about the ownership of transmission facilities that were operated by CEAS.

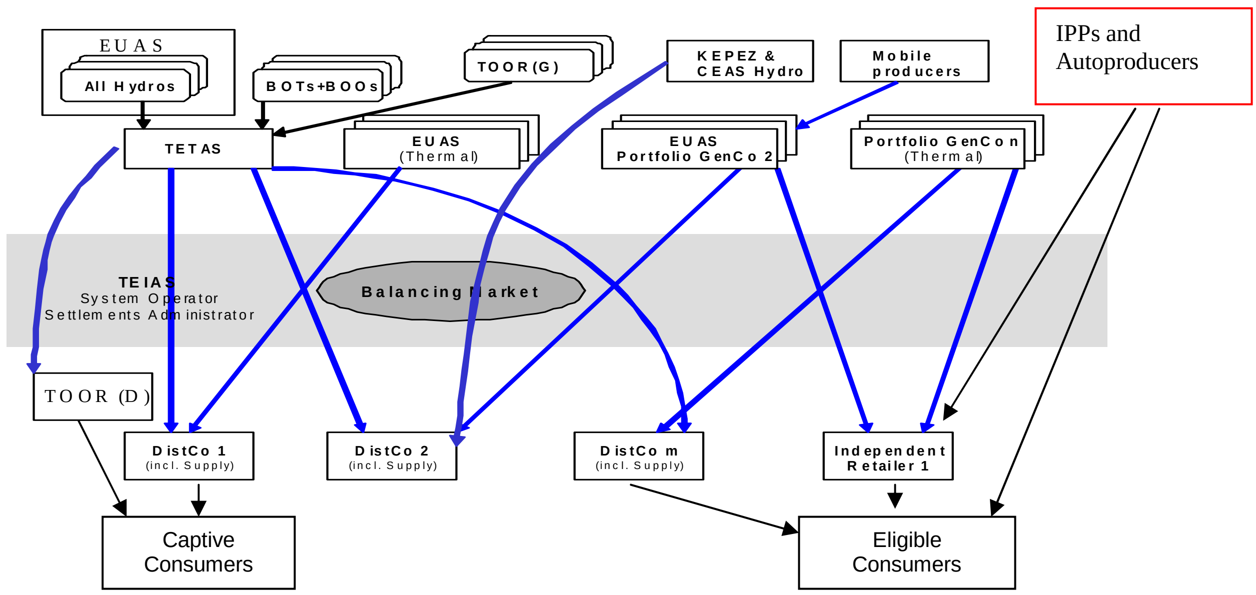
[18] All production, distribution and commercial facilities of these 2 companies were also seized in June 2003, on grounds that they persistently violated provisions of the TOOR concession agreements that they had signed with the government to run the power stations and distribute electricity.

[19] EMRA (2003).

(generation) contracts and will assume other stranded costs such as the debts and employment liabilities of EUAS and TEIAS. In fact, dealing with stranded costs is one of the main reasons for the creation of TETAS.

Regarding end-users, eligible customers may buy electricity from their regional distributor/retailer or TOOR distributor, but may also buy directly from a wholesaler, from a new independent retailer or from an independent generator. Captive customers, on the other hand, must buy their electricity from a distributor/retailer in their region, but they have the right to buy from any retailer carrying out the same commercial activity in the region, either their existing regional distributor/retailer or TOOR distributor or any other new retailer in the region.

Figure 1 Market structure



Source: Modified from the Draft Electricity Market Implementation Manual

The current market design does not envisage a centralised pool or power exchange. This means that dispatch is separated from the operation of the wholesale market. The actual real-time equality of demand and supply, given the bilateral contracts, will be carried out by the system operator through purchases and sales in a balancing market. For this purpose, a market System Balancing and Settlement Center[20] is to be established within TEIAS. In principle, it is expected that the balancing market make up a small percentage of total demand and be used for adjustments at the margin.

Privatisation

The new regime envisages eventual direct privatisation in generation and distribution. Transmission assets are to remain under government ownership. Foreign investors cannot take a controlling interest in generation, transmission and distribution sectors.

[20] In the English translation available on EMRA's website, this is called the Market Financial Reconciliation Center.

Details of licensing procedures, market operation, tariffs, vesting contracts, privatisation and stranded cost mechanisms have been left to secondary legislation and decisions.

Vesting contracts

Vesting contracts are an initial set of bilateral contracts put in place by the government between companies that it owns (or between state-owned companies and private companies such as independent retailers where the government decides the contract structure and the retailer decides whether or not to buy it) to provide a smooth transition to competitive markets and to improve predictability of revenues during this transition. The contracts remain with the companies when they are privatised, the private buyer paying for the company and its package of contracts. Vesting contracts are intended to cover a large portion of sales (90-100%) of each supplier initially. This share will be reduced gradually in later years and replaced by freely negotiated bilateral contracts as the vesting contracts expire.

Vesting contracts are expected to include: purchases by TETAS from all EUAS hydro plants, sales from TETAS to all distribution companies and distribution TOORs to cover franchise captive consumer demand (with part of hydro capacity available for the balancing market), and sales from affiliate portfolio generation companies to all distribution companies.

The main objectives of vesting contracts are (OECD 2002, EMRA 2003):

- Avoid large physical imbalances of large financial risks to participants; avoid chaotic prices
- Ensure that distribution companies are not over-exposed in the balancing market
- Allow a period of time for learning how the bilateral market works before distribution companies undertake their own contracting
- Allow companies to be privatised with a set of matching purchase and sale contracts so that potential buyers can value them. Allow government to influence the portfolio mix of generation purchased by each distributor to ensure there is reasonable regional balance
- Allow for the determination of a reasonable flow of funds between companies (e.g.: minimum sales levels for generation companies)

Public service obligations

The EML under the consumer support section of Article 13, and the Tariff Regulation under Article 20, allow for an explicit cash subsidy: direct cash refunds to consumers without affecting the price structure and the prices ‘in cases where consumers in certain regions and/or in line with certain objectives need to be supported’. The mechanism for allocation of these direct cash refunds (‘amount, procedure and principles’) has not been defined in the primary legislation, and has been left to be established by the Council of Ministers upon proposal by the MENR.

The independent regulatory authority

The new regime establishes the independent Energy Market Regulatory Authority (EMRA), governed by its own Board.[21] The main functions of the Authority include:

- Apply and oversee the new licensing framework
- Prepare and publish secondary legislation concerning electricity and natural gas markets[22]
- Enforce rTPA
- Apply a new transmission and distribution code
- Determine eligible customers over time
- Regulate tariffs for transmission and distribution activities (connection and use-of-system) as well as provision of retail services to non-eligible customers, plus the wholesale tariff of TETAS
- Perform tenders for city gas distribution networks
- Follow the performance of all actors in the market
- Follow and protect customer rights
- Apply sanctions to parties violating the established rules

IV. Main challenges

The actual development of competition in the Turkish electricity market is likely to take time due to a number of challenges and difficulties especially having to do with exit from the old system. Primary among these challenges is the fact that most generation capacity is currently either under government ownership or tied up with take-or-pay contracts that leave no room for competition. Additional challenges have to do with financial difficulties that may persist in distribution. Finally, liberalisation will entail significant tariff rebalancing which may pose serious political challenges.

Stranded costs and competition in the generation market

As of 2002, private generators accounted for about 25 percent of capacity and autoproducers for about 12 percent (Table 1). Under currently committed BOO, BOT and TOOR contracts (see below), and assuming no privatisation in generation, a significant increase in autoproduction capacity but little additional new entry for the foreseeable future, the share of the public sector will remain at about 60% by 2010. Publically-owned hydro assets alone account for about a third of total generation capacity.

[21] The EML provided for an authority responsible for the regulation of the electricity sector. This was changed through Law 4646 (the Natural Gas Market Law) which designated a single authority for both the electricity and gas sectors.

[22] With respect to the Electricity Market, EMRA has issued, among others, regulations on licensing, tariffs, export and imports, eligible consumers, as well as a grid code and a distribution code. These are available at http://www.epdk.gov.tr/english/regulations/electricity.htm.

Table 1: Electricity Generating Capacity (MW)

	2002	(%)	2005	(%)	2010	(%)
Non-EUAS plant						
BOO	3,830	11.3	5,810	14.4	5,810	13.5
BOT Thermal	1,450	4.3	1,450	3.6	1,450	3.4
BOT Hydro and wind	899	2.7	899	2.2	899	2.1
TOOR transferred	650	1.9	650	1.6	650	1.5
Mobile	623	1.8	823	2.0	823	1.9
Kepez and CEAS	1,120	3.3	1,120	2.8	1,120	2.6
Autoproduction	3,944	11.7	5,344	13.2	6,844	15.9
Sub-total	12,516	37.0	16,096	39.8	17,956	41.7
EUAS plant						
Natural gas	3,983	11.8	3,983	9.8	3,983	9.3
Hydro	10,326	30.6	11,685	28.9	12,762	29.7
Coal/lignite and fuel oil	6,972	20.6	8,692	21.5	8,692	20.2
Sub total	21,281	63.0	24,360	60.2	25,437	59.1
Total capacity	33,796	100.0	40,455	100.0	43,032	100.0

Source: ECA (2002)

Note: the forecasts in the table exclude additional hydro plants with signed intergovernmental protocols scheduled for 2007 and after.

A significant share of privately operated assets are tied with contracts entailing fixed amounts and prices, and therefore will not be deployed according to competitive forces. As highlighted in Table 1, the largest share is accounted for by the 3 BOO plants in operation as of 2002, with 2 additional plants to start operation by end-2003. Total energy sold by the BOO plants in 2002 was 36.4 GWh, accounting for 34.3% of total energy purchased by TETAS in 2002. There are also 4 natural gas, 17 hydroelectric and 2 wind BOT plants already in operation. For these BOT projects, total energy sold in 2002 was 12.7 GWh, accounting for an additional 11.9% of total TETAS consumption. Therefore, 46.2% of all purchases made by TETAS are based on existing tied BOO and BOT contracts.

There are an additional 30 BOT projects with a capacity of 2771 MW with procedures not completed, whose legal status still is not clear. The anti-competitive nature of these contracts, and their apparent high cost have created a public reaction against them. Regarding TOORs, two generators (one lignite and one hydro) are operating. There is an additional 3926 MW of TOOR contracts that have not been transferred, whose legal status is not clear (their transfer would have little effect on available capacity, as they represent existing production)

Stranded costs, that is, costs incurred within the previous market structure that cannot be economically recovered within a competitive market structure include high operating costs of old and inefficient generators, long-term power purchase agreements with high prices, removal of production subsidies, and high staffing (payments of redundancies resulting from transfer of operations to the private sector, including pension liabilities for workers able to retire). Stranded costs create uncertainty for new investors and risk stifling competition. There are two main sources of these stranded costs. First, there appears to be substantial surplus generating capacity, with reserve margins having been over 60% in 2002, and possibly remaining substantially above the minimum 25% or so required for system security for the next years, depending on the evolution of demand. This substantial level of excess capacity leads facilities to have low capacity factors and hence lower revenues than required to recover full costs. Surplus generating capacity may have been driven at least in part by overly-optimistic demand forecasts, a natural occurrence in a system where the costs of substantial publicly-promoted over-building are not apparent while the costs of under-building are immediately obvious and extremely high. Of course the unanticipated two earthquakes and the economic crises that Turkey has suffered over the past years also play a significant role in explaining the deviation between initial demand forecasts and actual demand. The second main source of stranded costs are the long-term power purchase contracts entered into by the state during the past years with private producers with especially high front-end costs. The high cost of electricity from many of these contracts makes it difficult to generate the required revenues to service these contracts without increasing average wholesale and retail prices.

The long-term Treasury-guaranteed generation contracts and associated stranded costs have two important implications. The first relates to competition. Prospects for competition among generators are poor for the immediate future unless there is new entry by IPPs or autoproducers. However, new entry may exacerbate the problem of stranded costs, since generation capacity is already expected to be in substantial surplus. Furthermore, the existing finalised BOT, BOO and TOOR (generation) contracts adversely affect the possibilities of market liberalisation by preserving a non-level playing field (where favoured generators benefit from State guarantees, privileged trading relationships and non-competitive pricing, and thereby face substantially fewer market risks), by preventing pressures on prices from new entry, and by preventing flexible price and quantity adjustments to unanticipated market shocks (like the recent macro crisis).

The second problem has to do with the contingent liabilities created for the government. If revenues to the electricity sector do not cover payments to the Treasury-guaranteed generators, then the guarantees would be activated and payments would have to be made from the government's constrained budgetary resources to subsidise electricity (whether it was actually used or not). The substantial state-owned hydro resources that have been developed to-date go some way to minimising these potential liabilities, as the low cost of hydro can be considered as a 'stranded benefit' that can be used to help offset the sizeable transition-related stranded costs. Indeed, the idea behind initially contracting all state-owned hydro assets to TETAS is to enable it to cover a substantial part of the stranded costs through the profit on sale at market levels of this low cost power. However, under some low demand scenarios, even with hydro being compensated at the very low price of USD 0.002/kWh, TETAS may be faced with a substantial revenue deficit. Under worst case but not necessarily zero-probability scenarios, ECA (2002, Table 29) calculates these deficits to be between 100-800 million USD annually (adding to a total of USD 4.1 billion) between 2003-2010.[23]

Revenue deficits, technical losses and private participation in distribution

The main challenge in distribution in relation to creating competition is to ensure the creation of creditworthy entities that can act as counterparts to incumbents and potential entrants on the generation side.

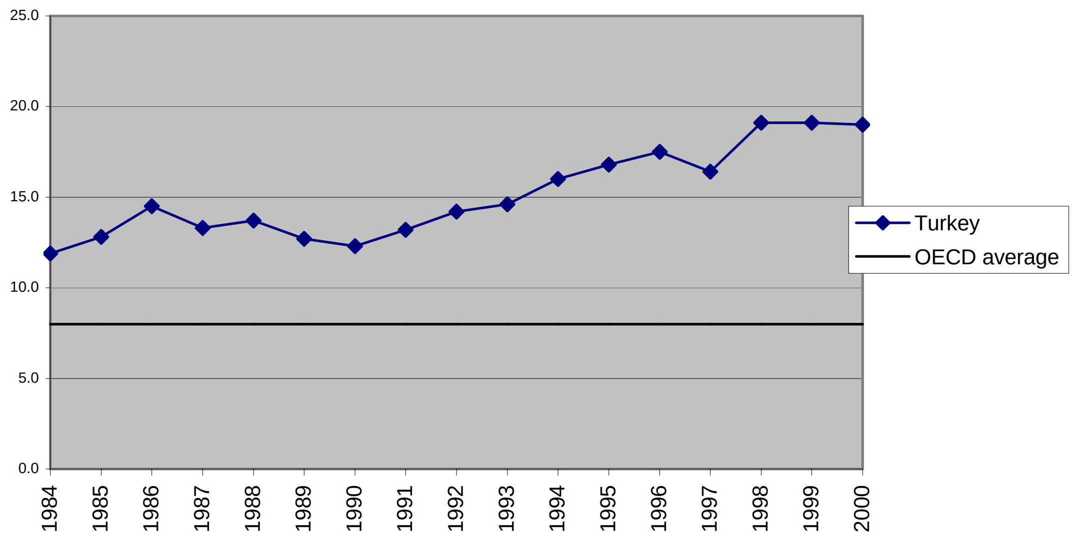
There are presently 33 distribution areas. In a few regions (including Kepez and CEAS), concessions that had permitted operation of the networks by private investors have been cancelled. Additional tenders for TOORs were held for other regions in 1996. Bidding occurred through offers of distribution tariffs over the concession period, with lowest bidder winning. This means, as with the fixed price BOT, BOO and TOOR generation contracts, that any efficiency gains over the franchise period will not be passed on to consumers. In addition, winners were to commit to reduce technical electricity losses; gains or losses generated by changes in electricity losses would be appropriated fully by the company. An additional problem with distribution TOOR contracts is that they may prevent the subsequent imposition of a harsh efficiency-enhancing incentive-based tariff formulae, since these companies would then lose profits relative to the initially-promised fixed cost-plus tariffs, and they would therefore seek (and have grounds for) compensation. Finally, to the extent that the desirable distribution regions were cherry-picked through the TOOR process, this would prevent sufficiently marketable and competitive groupings to be formed from the remaining regions, and prevent a matching of most- with least-desirable sub-regions, thereby jeopardising distribution privatisation and possibly resulting in non-sellable assets.
The distribution sector suffers from growing operating revenue deficits, in turn driven by:

- Electricity theft and non-payment (about 14% of total energy purchased by TEDAS with large regional variation)
- Technical losses (about 7%)
- Free or un-billed electricity supply (4%, especially street lighting)

The OECD average of electricity losses (which is mainly driven by technical losses) is about 8% (Figure 2).

[23] The worst-case scenario entails demand growth at levels projected by the OECD, which are lower than those projected by MENR; and with all pending BOT and TOOR projects going ahead. In addition to assumptions on demand, results also are sensitive to the assumed level of wholesale prices that might emerge with new entry (lower wholesale prices will create larger operating deficits for the relevant generation plants selling to TETAS), and to the assumed minimum non-avoidable costs of the state-owned plants that must be covered (sustainable operating cost levels, rather than just to cover O&M, fuel and debt service costs, could lead to revenue deficits even with the higher MENR demand levels).

Figure 2: Losses- Turkey vs. OECD



Theft and non-payment is fundamentally a political economy and distributional problem that has implications for rebalancing tariffs.

Tariff rebalancing, social protection and industrial competitiveness

Industrial prices are almost as high as household prices, unlike in more liberalised markets where industrial prices are often less than half those of households (lower industrial prices reflect the lower unit cost of delivery of large amounts of electricity to industrial customers). According to data on end-user prices, Turkish industry faces one of the highest costs in Europe. However, equally noteworthy is that Turkish household prices are not particularly high, in the lower end of the range for Europe. Out of 32 countries listed in the latest IEA report (Key World Energy Statistics 2002), Turkey is the only country (apart from India) where consumer prices are so close to industrial prices, with consumer prices being more than double the level of industrial prices in 8 of the EU-12 countries, over 3 times higher in Denmark. The numbers below (Table 2) suggest that although large industrial users are likely to see substantial price falls from increased competition, households and smaller industrial users are likely to see substantial price increases.

This large cross subsidy to households will not survive with liberalisation as eligible consumers are entitled to switch to lower-cost sources under bilateral agreements, and as less efficient and/or higher cost regional distribution systems reflect these costs in user tariffs. This issue of tariff rebalancing towards cost-reflective tariffs, if not properly handled, could jeopardise the entire reform effort by creating political

Table 2: Retail Prices for Electricity		
	Electricity for Industry cents/kWh	Electricity for Households cents/kWh
Austria	9.21	12.14
Belgium	4.77	13.23
Denmark	5.97	19.53
Finland	3.94	7.89
France	3.58	10.17
Germany	7.9	16.66
Greece	4.31	7.75
Ireland	4.62	9.57
Italy	9.3	13.42
Portugal	6.59	11.77
Spain	5.58	14.33
UK	4.96	10.1
Czech Rep	4.68	6.11
Hungary	5.21	6.98
Poland	4.76	8.34
Slovak Rep	4.35	6.28
Canada	3.86	6.01
US	4.27	8.5
Turkey	8.05	8.49

Source: International Energy Agency (2002)

pressures for back-tracking. It will have effects on:

- poverty and relocation incentives. Poorer households in the east are likely to see their prices rise most in the short term, while already overpopulated cities in the west with more efficient distribution systems face somewhat less steep tariff increases.
- employment and industrial competitiveness. Business users with annual consumption below the threshold, including all SMEs, will also likely see substantial price rises.

The income distributional dilemma faced by the authorities was reflected in recent difficulties regarding the creation of distribution regions. Months of work and an ultimate agreement reached among EMRA, MENR, TEDAS and the Treasury was rejected by the government as a result of intense pressures from localities that did not want to be included in regions designated as high-cost areas. EMRA responded by proposing instead province-based cost-reflective retail tariffs. The highest proposed tariff was for Hakkari, which is both one of the poorest provinces as well as with the highest incidence of theft (daily Radikal, 3.3.2003)

Wholesale market concentration and the dominant role of TETAS

In the design of the new market model, the role of TETAS is critical as an instrument to help resolve transitional stranded costs through market mechanisms, and thereby help protect captive consumers from sudden and large increases in wholesale prices. It is with this purpose in mind that it was decided that TETAS should be the holder of all legacy state-owned contracts and liabilities, including BOT, BOO, TOOR contracts as well existing import and export contracts, and play a key role as wholesaler trader of electricity. The EML requires TETAS to be financially viable and authorises TETAS to charge a wholesale price sufficient to cover its stranded cost obligations (based on the weighted average costs of the generation plants selling to it, including BOT, TOO and TOOR plants). However, there is no requirement for profitability on a year-by-year basis, but rather that surpluses and deficits should balance over a reasonable period. The initial contracting to TETAS of all state-owned hydro plants is intended to help it meet this financial viability criterion.

As the holder of the majority of generation contracts, TETAS will be the dominant seller in the market for the foreseeable future. Through its rights to hydro capacity, TETAS also will be the dominant participant in the balancing market. Given its dominant position, it will be critical that TETAS be effectively regulated. In the absence of effective regulation, there is no incentive for TETAS to keep its costs as low as possible, as it passes its costs fully to captive customers.

In practice, the ability of TETAS to raise the wholesale price to cover its stranded cost obligations is constrained by the prices that could be offered by new entrants (the cost of electricity from a new gas-fired CCGT power plant), to the extent that new developers are willing to take the risk of building new power plants over the next years. In that case, if the TETAS wholesale price is above the price that could be offered by IPPs, then distribution companies and eligible consumers will choose to buy from IPPs, causing TETAS' sales to fall. However, because TETAS costs have a large take-or-pay component from BOT, BOO and TOOR plants, its costs will remain high as its market share falls, leaving it to recover its fixed costs over a lower level of sales. To avoid such a vicious cycle of falling sales and required higher wholesale prices, TETAS cannot afford to charge a wholesale price significantly above the cost of a new gas-fired plant.

Inter-institutional coordination and a national electricity policy

There is a lack of strong centralised leadership taking an overall perspective of the electricity reform program, including on tariff, market structure, competition promotion and privatisation issues, and to ensure coordination of the 9 or more entities with separate management teams: MENR, EMRA, PA, Treasury, EUAS, TETAS, TEIAS, TEDAS, and Treasury. It would be highly desirable to achieve consensus among all main national stakeholders around a national electricity policy that presents a coherent strategy for market structure, that outlines what is meant by competition in the foreseeable future Turkish electricity market and how more room could be made for additional competition, and that articulates a well-defined desired end-state for the industry and a strategy for achieving it.

V. Possible competition-enhancing solutions

Evidence on the benefits of electricity reform is rather recent and most of the detailed studies concentrate on a number of well-known cases such as the US, UK and Scandinavian countries. Some studies do not provide strong conclusions. For example, a recent study by the OECD (Steiner, 2000) fails to find a significant effect of regulatory variables such as TPA and unbundling on industrial prices. Such variables are found to have an impact on the *ratio* of industrial to residential prices, but this finding may be capturing the impact of rebalancing rather than other components of reform. Privatisation is found to *increase* industrial prices. On the other hand, the same regulatory variables are found to have a positive impact on a proxy for efficiency.

Nevertheless there is a general consensus among analysts that the key to welfare enhancing electricity reform is to have adequate competition in generation. Efficiency gains, especially due to cost reduction, are easiest to obtain in this segment of the industry. However enhanced competition is necessary for those efficiency gains to be passed on to consumers. Below we discuss a number of options that can accelerate the development of competition in the Turkish context.

Transitional regimes for tackling stranded costs

There are a number of possible options that the government will need to consider in minimising and addressing stranded costs. A lowering and more rapid resolution of stranded costs will have a number of benefits, in particular allowing a more rapid introduction of competition. It also would allow a more rapid release of hydro plants for privatisation, which would have the added benefit of enabling generators and retailers to offer more valuable contract shapes, and providing flexible energy to the balancing market and for the setting of day-time and peak prices.

Possible options include:

- A final resolution of all outstanding non-finalised BOT and generation TOOR contracts that does not increase stranded costs. Given the potential costs to the economy and the electricity sector in terms of both additional fiscal costs and foregone competition benefits, it appears to be in the public interest not to provide Treasury guarantees for most of the non-finalised BOT and TOOR projects, while remaining open to negotiated win-win solutions subject to this constraint. The basic strategy of EMRA has been to encourage project sponsors to apply for generating licenses and to act according to the dictates of the new market model. Given the potential reputational costs to Turkey as a destination for FDI inflows of such a unilateral government decision, the government should remain open to negotiate with project sponsors on a case-by-case basis to seek acceptable solutions that do not burden Turkey with additional expensive and unneeded power. The broader international impact should not be too negative as long as the underlying public policy reasons are clearly explained and the initially-agreed contractual terms are adhered to, including appropriate compensation being offered following arbitration if a negotiated solution is not possible.

- Voluntary win-win renegotiation of tariffs. The existing BOT contracts are heavily front-loaded with higher capacity charges in the first 5 to 10 years of operation. By exploring the scope for non-unilateral improvements to the contracts in the spirit of the basic principles of the EU 1996 Directive, the level of stranded costs can be lowered. Possible win-win modifications could include lowering the average tariff level over time and flattening the tariff slope in exchange for removing the T (transfer requirement) in the BOT and/or alternate approaches for providing an equity return over a longer period. To facilitate negotiations, these potential win-win modifications that would transform the existing BOT contracts into IPPs should be unbundled and discussed separately (Sevaioğlu n.d.): (1) tariff smoothing, flattening the payment curve by retarding the higher payments of the first years; (2) ownership transfer, transforming the BOT to a BOO model by subtracting the value of the assets from the tariff profile; (3) price risk transfer, removing the take-or-pay condition by compensating the difference between the agreed and estimated stabilised market price; and (4) volume risk transfer, compensating the estimated revenue loss when the company fails to find customers paying the same price as agreed in the initial take-or-pay clause. [we could include a diagram here and attribute to Osman bey] The potential for outsiders to challenge any such negotiated solution should be minimal as long as project sponsors are no better off than they were prior to the renegotiation. Stranded costs also could be reduced by agreeing to lower the gas prices charged in individual contracts by BOTAS.

- Postponing or cancelling non-finalised inter-government protocols on hydro. Inter-governmental protocols refer to commitments between 2 or more sovereign governments for specific investments. To help lower the extent of excess generation capacity on the system, consideration should be given to alter the existing pipeline of country-to-country protocols. Since such protocols are political undertakings rather than established private contractual rights, modifications in line with unexpected public policy imperatives may be easier to achieve.

- Low pricing of TETAS-contracted state-owned hydro generation assets. By pricing hydro at its O&M cost, it is possible to reduce the revenues required to pay for the stranded costs. However, depending on the demand scenario, low pricing of hydro may not be adequate on its own.

- Stranded-cost levy. A levy or additional surcharge could be applied in various ways to obtain revenue to cover any deficit, but the simplest way would be to apply it to final electricity consumption. Imposing the levy on final consumption ensures that eligible consumers and distribution companies cannot avoid the levy when they buy power from sources other than TETAS. A stranded cost levy may be the easiest and best solution from the economic point of view. However, the levy would result in an increase in prices to end consumers: the approach suffers from the obvious drawback that the tariff would rise.

- Sale of hydropower plants. Selling (or leasing) hydropower plants to the private sector and utilising these sales revenues to cover the stranded cost deficits is an option that also should be considered. This would have a similar impact to the option of diluting the high BOT, BOO and TOOR generation costs with low-cost hydro, but the advantages would be two-fold. First, revenues would be realised immediately, at a time when Treasury resources are particularly constrained. Second, it would allow market liberalisation to go ahead more rapidly. However, an important consideration for the government is whether adequate revenues would be realised from the sale of what are potentially extremely valuable assets in the balancing market in the immediate-term, or whether higher revenues could be realised once the market begins functioning, once experience accumulates on how the new market would value hydro plants and hydro electricity, and once investor confidence increases with additional regulatory oversight experience. On the other hand, the benefit of more rapid liberalisation or at least a staged privatisation approach with annual auctions for some hydro (either for capacity in say 1 MW tranches of all hydro, or for all of a specific plant for 1 year leases) may well outweigh the foregone higher revenue proceeds of a later sale, in particular if the earlier prospect of privatisation helps spur better regulatory oversight and other market-friendly policy decisions during the shorter pre-privatisation period (driven by the pressures of an incipient privatisation).

Tariffs and universal service

Industrial tariffs are expected to come down and household tariffs are expected to increase from tariff rebalancing. However, in assessing the impact of overall tariff changes on consumer welfare, it is important to take into account the decrease in the prices of all goods in the household consumer basket that will decrease as a result of the decreased cost of this key intermediate input. More generally, efficiency gains from cost-reflective prices are expected throughout the economy.

To mitigate the effect of rising household tariffs, the first priority should be to reduce costs by eliminating theft and non-payment rather than adjusting household tariffs upwards by the full margin required to cover costs (inclusive of theft and non-payment). In addition there will be the need for a means-tested system for providing support to those who cannot afford the higher retail prices and are eligible for such social protection (in part replacing the current reliance on theft and non-payment of bills as a social safety net). This has fiscal implications for forthcoming budgets as well as requiring the implementation of workable eligibility and delivery mechanisms.

As part of a possible policy solution, the EML and the Tariff Regulation allow for an explicit cash subsidy under a mechanism to be established by the council of Ministers. Provisional Article 12 of the Licensing Regulation allows for vesting contracts, which could be bundled so as to offer lower-cost contracts to higher-cost distribution regions and thereby ease cross-regional adjustment. One additional mechanism to help ease the cost burden on residents in the eastern part of Turkey could be to use meters with a three-term tariff structure. By using such meters, it would be possible to offer extremely low prices during off-peak periods as well as thereby helping to reduce illicit utilisation.

Cross-border trade and the benefits of EU accession

Other EU countries have reported benefits from adopting the Electricity Directive, but problem areas remain (EC 2002c):

- Differential rates of market liberalisation. By 2002, while five countries had implemented 100% market liberalisation, the rest have opened up less than 60 % of their markets, with Denmark, France and Greece opening up only up to 35% of their markets so far.
- Disparities in access tariffs between network operators which, due to the lack of transparency caused by insufficient unbundling (e.g. management or accounting but not legal or ownership separation) and inefficient regulation, may form a barrier to competition.
- The high level of market power among existing generating companies associated with a lack of liquidity in wholesale and balancing markets, which impedes new entrants:
    - only in 3 member states do the top 3 companies have less than 50% market share; in 9 member states, the top 3 companies have more than 75% market share;
    - large divergences in prices continue to exist across member states

A central implication of the full internal market is that an important source of competition in countries where the generation market is concentrated would be cross-border transactions. However, the ratio of import capacity to installed capacity was more than 25 percent in only 4 out of the 15 EU countries to-date. Relying more on cross-border transactions requires better cross-border arrangements. The problem there is insufficient interconnection infrastructure between member states and, where congestion exists, unsatisfactory methods for allocating scarce capacity. Encouragingly, common guidelines on congestion management have been agreed at the 6th Florence Forum in September 2001. There has been more progress on cross-border tariffication. Following the adoption of a temporary mechanism for cross-border electricity exchanges in March 2002, EU market players involved in cross-border exchanges no longer have to pay a series of uncoordinated charges to transmission networks ('pancaking') since all transit and import charges have been removed. Under the new regime there is only a single export charge that is allowed (1 euro/MHW). Nevertheless, the EC remains worried about the pace of development of cross-border trade. By end-2000, four years after the adoption of the Electricity Directive, physical cross-border trade in electricity did not exceed 8% of total consumption, which "leaves the EU far from a real, competitive internal market" (EC 2002c, p. 22)

In the case of Turkey, obstacles to increased cross-border trade include:

(1) Operating standards and inter-connector capacity – currently Turkey does not comply with the main continental European UCPTE operating standards and therefore could not connect its network synchronously; it is planned that in 2006 Turkey will be part of the UCPTE network. A 400kW overhead line to Greece is planned to be commissioned by 2006 (with a sub-sea cable connecting Greece with Italy and the western Europe network). A connection exists with Bulgaria when a portion of the Turkish network in Thrace is disconnected (imports from Bulgaria account for 3% of domestic consumption according to OECD).

(2) Cross-border transmission pricing and settlement coordination – currently the tariff framework for cross-border transactions is not very well developed yet, so it is still organisationally and economically difficult for individual electricity customers to choose suppliers situated in another member state, though proposals for more refined systems of cross-border pricing are being developed.

(3) Technological transmission losses over distance – absent a DC (direct current) direct transmission link (as between Greece and Italy), the cost of running electricity through intermediary transmission networks makes shipping electricity from Turkey to France or the UK prohibitive. So trade in the medium-term will remain fairly localised, possibly including Greece, Italy and Bulgaria-Romania. Given that Turkey has lower-cost endowments than neighbouring countries, it is likely that the eventual flow will be from Turkey to neighbouring countries, implying a gradual increase in Turkish prices as low-cost assets are fully utilised.

Without doubt, one of the most significant benefits of EU accession for Turkey in the electricity sector would be the stability provided by anchoring Turkish regulations and practices to EU norms and practices. Given the degree of political instability prevalent in Turkey (especially, until recently, the predominance of coalition governments and the short tenure of governments), and given that in the past the discretionary authority of the state has not always been used in the clear interest of the public (the existing stranded contracts in electricity providing a clear example), the European anchor will provide a strong signal of discrete and irreversible regime change from past practices that may have caused concern among both foreign and domestic players in the electricity industry. The confidence-boosting effect on potential investors who otherwise may continue to be reluctant to enter the Turkish electricity market is likely to be significant.

Privatisation and entry-promotion strategies for generation and distribution assets

It has been asserted that one of the worst features of EU electricity reforms until the recent proposals is that continued vertical integration is allowed – in Europe, common ownership of generation and distribution is increasing. Vertical ownership separation or unbundling of distribution from generation at the time of privatisation seems to have become the consensus approach in the rest of the world, having been adopted successfully by England/Wales, Latin America (including Argentina, Bolivia, Chile, Colombia, El Salvador, Guatemala and Peru as the most-cited examples), a number of transition economies, and Australia and New Zealand. Malaysia and many countries of the EU are exceptions to this pattern.

On the other hand, the recent crisis in California has raised doubts, including in Europe, about the stability and viability of unbundled electricity markets (Newbery 2001, 2002b). It has been argued that generating companies in California had incentives and ability to behave strategically, withhold capacity and thereby manipulate and increase wholesale prices (although there were other factors at work as well, including flawed market design, see Box 1). By contrast, it is argued, integration of generation with distribution eliminates these incentives and creates a more stable market structure.

Box 1: California's Electricity Crisis

In 1996, the California electricity industry underwent a fundamental restructuring. Before reforms, there were three vertically integrated utilities that owned and operated generation, transmission and distribution assets. Retail prices were regulated by state regulators whereas wholesale prices were regulated at the federal level by FERC. Prices were higher than US averages; this was blamed on the vertically integrated structure, and long-term contracts with independent power producers (IPPs). Hence there was a public demand for reform.

The most important features of the Restructuring Law of 1996 were as follows:

- Retail customer choice. Customers could choose a competitive electricity service provider (ESP) or buy default service from the local utility distribution company (UDC)
- Incumbents were required to provide open access to their transmission and distribution networks to competing generators, wholesale marketers and ESPs at regulated prices
- UDC default service price was set equal to the wholesale spot market prices determined in the day-ahead real-time markets
- There was a retail rate freeze of maximum 4 years to recover stranded costs of generating assets (the assumption was that wholesale prices would be lower than frozen retail levels).
- California Independent System Operator (ISO) and California Power Exchange were created
- Two largest Investor Owned Utilities (IOUs) were ordered to divest at least half of fossil generating capacity.
- IOUs were required to meet default service obligations by purchasing from the spot market (i.e. they had to sell power from their remaining assets and then buy it back to meet their default service demand). They were "short" for the difference between what they could sell and what they had to meet in terms of default demand. They were not allowed to hedge by forward contracts with generators because it was feared that such contracts could be anti-competitive.

Market design represented a series of incoherent and fragmented compromises between interest groups (bits and pieces from different designs) rather than a well-thought strategy. It was also very complicated. It relied more on individual generator owners to make commitment and dispatch decisions and manage congestion based on their self-interests (in that sense it was closer to the New Trading Arrangements in the UK, than the previous POOL system). There were serious episodes of horizontal market power problems: given rigid capacity constraints, small amounts of withholding of capacity resulted in large price increases. The build-up of new capacity turned out to be very slow. In the meantime California started to experience a rapid increase in demand. The IOUs became increasingly reliant on the spot market. Customer switching to ESPs was slower than expected; that meant large default service obligations for the IOUs. The ban on hedging contracts made their situation more difficult. As a result, a large fraction of demand was served through the volatile wholesale market.

The meltdown of the system was triggered by dramatic increases in the wholesale prices that utilities had to pay. The main reasons for the increase were rising natural gas (input) prices, a large increase in demand (due to abnormally hot weather, high economic growth), reduced imports and rising prices for nitrogen oxide emissions credits. In addition, there were serious market power problems. It has been estimated that about a third of price increases is attributable to market power and strategic behavior by players. High prices also further distorted incentives. For example, ESPs lost incentives to sell in the retail market because they could increase profit by selling in the wholesale market.

Because retail prices were frozen, the utilities started experiencing financial problems and credit-worthiness declined. Their requests to increase retail prices were turned down by the state regulator. Finally they went bankrupt. The State government practically took over supply.

Bad luck played an important role in the Californian crisis, in the sense that a large number of adverse events jointly triggered wholesale prices. However, flawed design and existence of market power made the system vulnerable to adverse shocks.

Source: Cabral (2002); Joskow (2001)

An assessment of which way to go must include weighing the benefits of mitigating wholesale price risk that vertical integration can provide against the costs of foregone competition and foregone effective regulation. We believe that the arguments point to vertical separation as the preferred initial configuration, allowing markets to reconfigure assets at a later stage if desirable (subject to oversight by the competition authorities). Whether or not the state-owned thermal generation plants should be privatised as a small number of bundled portfolio companies or sold as separate units depends at least in part on how geographically apart from each other they are.

Mitigating wholesale price risk. The recent rush towards vertical mergers in England/Wales has been driven at least in part by their move from a compulsory, single-price power pool to a bilateral contracts framework where there would no longer be a single price for delivery of electricity at any particular time but rather directly-negotiated prices between buyers and sellers (and substantial penalties for generators and customers that deviate from their contracted levels). The wholesale price risk that arises in a bilateral contracting environment translates directly into profit risk in an unbundled structure: a high price shifts profits to generators away from the retailing business, while a low price benefits retailing at the expense of generators. This risk can be reduced by vertical integration in which generators are assured of a captive market. Vertical integration also reduces the transaction costs of contracting, and reduces the risk of failing to find a buyer and hence being forced into a distress sale in the short-term balancing market. On the other hand, the larger the share of the market covered by vertically-integrated companies, the harder new entry will be and the more disadvantaged will be those companies that remain non-integrated.

Developing competition where possible. If a key objective of the reform is to stimulate a stable provision of low-cost, low-priced electric energy, international evidence suggests that sufficient competition is the best means to achieve it. A negative aspect of vertical integration is that the monopolist distributor will in many circumstances be able to increase its profits (together with delayed innovation) at the expense of society by favouring its own integrated generating companies over more efficient (existing and potential that may not enter) generators. Ownership separation removes the incentive for market foreclosure. While there remain economies of scope between generation and transmission/distribution that may suggest benefits from full vertical integration, there is also quite a bit of evidence that benefits from unbundled competition may be substantial. A telling example is the early experience of Scotland, where the 2 producers were privatised as vertically integrated companies, and England/Wales, where there was strict vertical separation at the time of privatisation. Prior to the reforms in 1990, Scottish prices were around 8% lower than England/Wales, while in 2000 Scottish prices were 5% higher, a swing of 13%.[24]

Facilitating effective regulation. If the regulators of the distribution monopolies are unable to detect and/or prevent discriminatory treatment towards favoured generators, many of the benefits of competition would be lost, casting doubt on the benefits of the overall liberalisation project. Vertical ownership separation facilitates the job of the regulator, by removing incentives for non-transparent transfer pricing, differential

[24] OECD Reviews of Regulatory Reform, UK, 2001.

quality of access to the wires or other discriminatory treatment between distributors and generators, and thereby making it easier for regulators to get information regarding true underlying costs and to secure fair access to the networks. The much more difficult task of effectively regulating vertically integrated companies, if that is to be an outcome preferred by the markets at a subsequent stage, should only be attempted by more seasoned regulators following a significant period of learning-by-doing in an unbundled environment.

In terms of sequencing, it is appropriate first to privatise distribution companies and ensure commercial management of those assets – to allow creation of financially viable companies that in turn allow private generators to structure bankable projects without government guarantee.

Newbery (2002b, c) provides a list of four conditions that are necessary for unbundled electricity markets to create socially beneficial outcomes. The first is that potential suppliers must have access to the transmission system. This is best achieved by unbundling transmission from generation and securing TPA, both of which are satisfied in the Turkish design. The second condition is the existence of adequate and secure supplies of electricity. This requires the existence of adequate transmission and generation capacity. This condition also seems to be satisfied in the Turkish case, at least in the short to medium term, given the substantial amounts of excess capacity available at present.

The third condition is that there must be a sufficient number of untied generation companies so that generation is truly competitive. This situation is perhaps the most problematic in the current Turkish context, given the sizeable amount of generation capacity that is either state-owned or with tied quantities and prices through long-term contracts. Thermal generation assets under public ownership can in principle be re-grouped prior to privatisation to create a number of viable companies, and these affiliate portfolio generation companies can be granted managerial and financial independence in order for them to perform their activities in accordance with more competitive conditions even prior to privatisation. This would be desirable in any case in order to put at least a minimum amount of structurally-based competitive pressure on existing state-owned thermal plants for increased productive efficiency and lower costs. However, the weight of tied generation assets that have been contracted to private parties through BOT, BOO and TOOR contracts may continue to prevent sufficient competition from emerging for some time, particularly to the extent that hydro assets also remain contracted to TETAS over the medium term to ensure its financial viability. This is the area where bold policy measures to reduce stranded costs and allow earlier hydro release to the market could yield substantial benefits.

An alternate but complementary way to increase competition and reduce market power in generation markets is through policies that work on the demand rather than supply side, by increasing the elasticity of demand, that is, by promoting stronger customer response to price changes. Traditionally, all customers pay fixed prices (annually negotiated fixed price contracts for industrial customers) that may vary in a mutually agreed manner on a daily or weekly basis, but independent of fluctuations in wholesale prices. As a result, the drop in demand in response to a rise in market price is negligible, greatly facilitating the exercise of market power. The key here is to induce customers to reduce consumption when prices rise. There are 2 options.

Interruptible contracts, which give the electricity supplier the right to curtail supply or specific appliances to be rippled off for short periods of time when price exceeds some level, may be promoted –if necessary through subsidies given their positive externality—for customers who can switch to other fuels or self-generation. The preferred option, again promoted through subsidies if necessary given their positive spillover, is to subject customers, especially the largest, to real-time (time-of-use) metering and billing. By giving end-user customers the technology not only to observe but to respond to real-time prices, they are empowered to directly modify their purchasing habits accordingly.

A powerful additional mechanism to enhance customer response to price changes is by promoting competition in retail activities. As earlier discussed, the EML allows for the activity of several retail companies in a distribution region in addition to the retailer that belongs to the distribution company. [will add more here on pros and cons, and whether any additional measures are needed to stimulate such competition]

The fourth and final condition is that the liberalised markets should be adequately regulated. This means, inter-alia, that regulation should not be limited to naturally monopolistic segments but should include wholesale markets as well. The argument here is that relying solely on ex-post competition policy remedies to discipline strategic behaviour in wholesale markets may be insufficient in preventing large welfare losses. Instead, regulators may need to have competition powers to ensure that pricing in wholesale markets does not deviate too much for too long from costs.[25] This is an area which seems to have been overlooked in the proposed amendments to the Electricity Directive in Europe.

In the Turkish design, the wholesale tariff applicable to electricity sales by TETAS will be regulated so as to reflect TETAS' average purchase prices as well as its financial obligations (Provisional Article 1, Electricity Market Tariff Regulation). In addition vested contracts discussed above should prevent high volatility as the non-TETAS segment of the market develops. Given the initial monopolistic structure of the wholesale market in Turkey, it is appropriate that the behaviour of TETAS be closely regulated. However, as alluded to above, it may be desirable for the regulator to be granted additional oversight powers over the wholesale market even as the dominant power of TETAS dissipates over time.

VI. Conclusion

It will take some time before electricity reform in Turkey starts showing benefits that are appreciated by consumers. In fact, in the short run some consumers may be adversely affected as measures are undertaken to correct for past mistakes. On the other hand, the slow pace of market development may be turned into a blessing. Electricity reform of the Turkish type is radical and entails huge uncertainties. The slow pace of liberalisation caused by inherited stranded costs should allow market players and regulator alike to experiment and adjust the rules wherever necessary.

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[25] For example in the US the Federal Electricity regulation Commission has a statutory responsibility to ensure that prices are "just and reasonable", which provides it with authority to replace market-determined with regulated prices. See the discussion in Newbery (2002c).

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