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Transmission Access Pricing for Renewable Energy Generation

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ABSTRACT

The contribution of transmission access pricing in promoting renewable energy is akin to the role of a pit crew member in a Formula 1 race. It is out of the spotlight, but can make or break the outcome. This study attempts to refocus that spotlight onto the less-seen role transmission access pricing plays. In doing so, the study derives from real issues faced by the executing agency of an ADB-funded loan program in the upgrading of transmission system capacity in Himachal Pradesh, India. Himachal Pradesh is a small, mountainous state in India's northern Himalaya region and has a policy mandate to maximize its considerable hydropower potential.

Given the planned hydropower capacity additions within the state, analyses have concluded that it was not just a least-cost solution, but a solution that was beneficial for environmental and other reasons, to maximize transmission line capacity in certain locations, "upfront". Excess capacity would only be fully utilized over time as planned hydropower projects come on line. Constructing surplus transmission capacity for future users raises three important questions, however: (i) is the surplus capacity justified from an economic (that is, a societal) point of view? (ii) if the surplus capacity is justified, who should pay for it?, and (iii) how, i.e., by what pricing mechanism, should it be paid for? Similar issues arise in other Indian states with ADB involvement, such as in Rajasthan, where there is a need to increase transmission capacity to accommodate solar and wind power generation development plans. As this is a widespread issue faced in many countries promoting renewable energy development, this study is a review-in-progress of pricing approaches used in various countries with similar regulatory environments. From these examples it is possible for policy makers to examine approaches which may be relevant to their particular needs.

ABBREVIATIONS

AEMC	–	Australian Energy Market Commission
ARR	–	Aggregate Revenue Requirement
CERC	–	Central Electricity Regulatory
HPPTCL	–	Himachal Pradesh Power Transmission Corporation Ltd.
INR	–	Indian Rupee
OFGEM	–	Office of Gas and Electricity Markets
MWh	–	Megawatt Hour
RAB	–	Regulatory Asset Base

I. INTRODUCTION

1. Transmission system constraints are a common barrier to renewable energy generation development. While conventional power generation facilities generally have more locational flexibility,[1] most types of renewable energy generation, namely wind, solar, geothermal and hydropower, must be sourced at the location of the resource. As these locations are often far from load centers (e.g., population centers with high electricity demand), this requires disproportionate transmission system investment and expansion to connect them to the grid.

2. This high cost of grid connectivity adds to the risks and uncertainties inherent in renewable generation development. Alternately, it is difficult to plan for and invest in, requisite transmission system expansion when the quantum and timing of generation capacity additions are uncertain. Investing in transmission assets to accommodate renewable generation is thus exposed to higher risks, and any obstacle to either the generation or transmission development side, negatively affects the other. This is a fundamental issue in that transmission and generation development depend on each other. Adding further to this dilemma is the intermittency of wind and solar generation output, particularly when compared to geothermal or hydropower. This requires transmission capacity to accommodate peak production but with the extra capacity unutilized in non-peak production periods, thus creating higher transmission costs on a per megawatt-hour (MWh) basis.

3. Standard practice is for power generators to pay the grid connection costs, as well as for system upgrades required to accommodate the additional power flows in the wider system attributable to their facility. For remotely located renewable energy with considerably higher connection costs, this requirement can be prohibitive and render a project unviable. Addressing how to pay for these costs is necessary in order to realize renewable energy capacity targets. This common situation is exacerbated in a developing country context, where investment funds are scarcer and existing grids may be less extensive, and where the cost of electricity is a higher percentage of average income levels, such that tariff increases are more burdensome on end users and often more politicized.

4. Constructing transmission capacity not just for current or near-term renewable energy generating capacity, but in order to accommodate longer term planned capacity additions, adds further cost pressure. There are numerous reasons to construct surplus transmission capacity. First, renewable energy resource-rich locations, such as high wind areas (including offshore locations), desert areas with high solar irradiation, or river basins with considerable run-of-river hydropower potential, tend to become clusters of renewable energy projects over time, and thus short-term transmission system requirements can quickly become inadequate. There can however, also be environmental and/or land acquisition constraints associated with building additional transmission lines parallel to existing ones. Surplus transmission capacity can promote further private investment in renewable energy, as pre-existing grid access removes a significant risk for developers. In general, it is economically efficient to build a certain amount of surplus capacity now for future users, and a failure to address the issues of prudent capacity margin can lead to transmission capacity shortages and inefficient investment in generation and transmission capacity. This paper will use the term "volume uptake risk" to describe the risk of unutilized transmission capacity (or "stranded" capacity) if the future generation does not eventuate or if demand for transmission capacity emerges more slowly than was forecast. There

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[1] Plant siting takes into account proximity to the load (e.g. demand) centers, access to transportation for fuel, transmission lines, water for cooling, as well as zoning, land acquisition, environmental and social impact considerations.

are three parties who can bear this risk – generators, transmission providers, and customers. It is a question of how the risk is allocated among these three parties, with it being the job of the independent regulator to best answer this question, given the particulars within their jurisdiction.

II. REGULATORY BACKGROUND

A. Tariff Methodology

5. Electricity tariffs paid by end-users include components covering the cost of generation, transmission, distribution, and various system administrative costs. The tariff attributable to the transmission portion of the cost of supply generally uses the Aggregate Revenue Requirement (ARR) approach (e.g. “cost plus approach”). This allows transmission utilities (or licensees) to pass on to transmission users, all costs incurred in constructing, financing and operating their assets, and in addition, to earn a return on their investment. Utilities thus are able to recover their regulator approved operating costs plus a return of, and return on, invested capital (both equity and debt) that financed the utility company’s asset base (consisting of the collective lines, substations, buildings, equipment, and working capital requirements required to provide the service). The rate of return on capital is the regulator-approved weighted average return that applies to equity and the long-term interest rates on borrowed capital. India is somewhat unique in that interest on debt and return on equity are split into separate components, yet this accomplishes the same revenue outcome. In India then, the ARR consists of:

1. Interest on debt financing
2. Depreciation (a.k.a. “return of capital”)
3. Operations and maintenance expenses,
4. Interest on working capital, and
5. Return on equity. (a.k.a. “return on capital”)

6. This transmission access pricing method transfers all but operational risk away from transmission licensees by ensuring that costs are recovered against regulator-approved investments and that investments earn a commercial rate of return. Volume risk is borne by transmission customers (that is, distribution licensees and ultimately end-use customers).

7. The benefits of traditional “cost plus” regulation are that rates are based on easily measured accounting costs, utilities are given an opportunity to earn a fair rate of return and have incentives to maintain high levels of service and means to invest in system expansion, and customers pay prices reflective of the cost to serve.

B. Transmission Regulatory Framework

8. Before a regulator would allow the cost recovery of transmission investments in an approved tariff however, the investments must first satisfy the regulator that they are consistent with optimal transmission system development and thus worthy of inclusion in the recoverable asset base. Thus, there is an application process where utilities submit the requisite technical details and system studies for regulator approval. In India, capital investment proposals are either approved by the Central Electricity Regulatory Commission (CERC) or, for intra-state matters, the respective state regulator. Similar processes exist in most other countries, such as the “grid investment test” in New Zealand and the Regulatory Investment Test (RIT) used in Australia. These tests include a cost benefit analysis of a proposed investment to ensure it is the most economical in addressing an identified need and that it provides the requisite system

reliability benefits. The process involves requesting comments from market participants on the proposed investment application, which are taken into account by the regulator. Traditional cost benefit analysis has evolved in countries with competitive, deregulated power markets to account for market factors. For example, in Australia, the RIT for transmission was modified on 1 August 2010 to also include market benefits from the proposed investment that may increase competition from generators and lower generation bid prices and thus overall system costs to end users.[2]

C. Who Pays?

9. Once a transmission investment is approved by the regulator, the transmission owner or licensee receives the ARR to recover the costs and earn a return on investment for building and operating the transmission assets, which in turn is paid for in the form of tariffs from users of the transmission system. The users of the transmission system are distribution companies who sell power to end-users (and thus pass on these costs through end-user tariffs which also include the charges for generation, distribution and other administrative costs). In many jurisdictions, generators are also considered users, particularly in a competitive environment where they must pay a fee to transmit or "wheel" their power over the grid. Thus it is common for a portion of the transmission costs to be borne by generators. System "beneficiaries" can thus be a combination of generators and distributors who pay access-based charges based on the amount of peak system capacity they must reserve to run their business (that is on a per megawatt [MW] basis), or in some cases based on actual power transmitted (on a per megawatt-hour [MWh] basis). There can also be short term, market-based purchases of transmission capacity.

10. From a regulatory viewpoint, there are two competing philosophies for who pays. A "beneficiary pays" approach argues that entities benefiting from the system should pay for it. A "socialization" approach argues that certain benefits, such as system reliability, cannot be easily assigned and therefore costs should be spread over all users. A survey study in the PJM electricity market (see references) in the United States summarizes the debate well:

> In practice, there is no broad consensus on precise definitions for "beneficiary pays" or "socialization", as evidenced by stakeholder disagreement over who should be considered beneficiaries or what constitutes socialization. Thus, it is exceedingly difficult to apportion transmission costs in a way that satisfies all stakeholders.[3]

11. These competing philosophies have been described as "deep" and "shallow" cost approaches, with a deep cost approach requiring the generator to pay all associated connection as well as grid upgrade costs, while a shallow cost approach socializes all but the direct interconnection costs.[4] To exemplify these competing philosophies, various countries and regulatory jurisdictions have taken different paths. For example, Germany opted on a shallow cost approach to promote offshore wind in order to address significant grid integration costs. One case study notes that for offshore wind, the grid integration costs are likely to exceed 15% of total generation costs and up to 24% for smaller projects.[5] Transmission Use Of Service

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[2] Australian Energy Regulator, September 2009. *Issues Paper – Regulatory Investment Test for Transmission*. Canberra.

[3] PJM. 2010. *A Survey of Transmission Cost Allocation Issues, Methods and Practices*. Norristown, PA, U.S.A. Pg. 1.

[4] Derk J. Swider et al, *Comparisons of Conditions and Costs for RES-E Grid Integration in Selected European Countries*, Green-net Report # EIE/04/049/S07.38561, 2006. Pp. 31-35.

[5] Ibid., pg. 61.

(TUOS) charges in Australia are a form of socialization, as transmission investment costs are recovered through these charges from all customers. Austria, on the other hand, has employed a "deep" approach where the burden is placed on the generator.[6] Lastly, there are interim models for entrepreneurial interconnectors or "merchant transmission" where the transmission provider and not just generators and end users, share some of the risk.

D. Regulatory Issues of Economic Efficiency and Equity

12. In almost all jurisdictions, economic regulators are required to consider two fundamental factors in making determinations regarding the pricing of infrastructure: economic efficiency and equity.

13. The concept of economic efficiency encompasses productive efficiency (ensuring services are provided at minimum cost), allocative efficiency (ensuring that resources are used to produce goods and services that provide the maximum benefit to society) and dynamic efficiency (in the face of changing conditions, ensuring consumption and investment decisions lead to efficient outcomes over time). For the purposes of this working paper, the authors have adopted the simplifying assumption that economic efficiency is equivalent to minimizing the present value of the financial cost of meeting demand for transmission capacity (that is, adopting the least-cost option). Least cost (and generally lowest long-run cost to customers) usually requires that transmission capacity be built in large capacity increments, often resulting in significant excess capacity at the time the augmentation is commissioned.

14. Equity can be regarded as fairness and unlike economic efficiency, which can be objectively modeled, equity is usually considered to be subjective. Examples of principles of equity used in tariff setting include:

- all customers should pay the same price for the same service (leading to "postage stamp" pricing);

- prices should reflect the cost of supplying particular customers or customer groups (leading to prices that are different in different geographic regions);

- customers should not be exposed to price shock (prices should vary slowly and predictably over time); and

- current customers should not pay for capacity required by future customers (inter-generational equity).

15. Clearly, many of these principles are conflicting and an economic regulator must take a view as to how equity is integrated into pricing in their specific circumstances.

16. Economic efficiency is concerned with maximizing social benefits from resources. Equity is concerned with the fair distribution of those benefits throughout society. Therefore, economic efficiency and equity may be in conflict and thus policy objectives often require a trade-off between the two. For example, cross subsidies in electricity supply reduce efficiency (customers paying for the subsidy see a higher marginal cost of supply and will therefore consume less than an optimal amount, perhaps not making efficient investment in electrically powered production facilities). However, where equity requires utilities to provide universal access to affordable

[6] Ibid., pg. 171.

electricity, cross subsidies are often necessary (the poorest members of the community cannot pay the efficient cost of supply). The economic regulator must attempt to balance economic efficiency and equity in the best interests of all customers.

17. This paper considers the specific problem that arises when the level of spare capacity in a system changes over time. If prices are set to recover the economic costs over the short term, then at times when there is significant excess capacity, current customers will be paying *now* for the spare capacity put in place to serve *future* customers. Intergenerational equity requires that future customers bear their own costs.

18. Consider the following examples:

Example 1

19. A utility has received a request to connect a 100 MW hydropower generating station to its transmission network. This station is in an area with significant planned investment in hydropower generation in the future, with the expectation that it will need to connect an additional 100 MW of generation every five years for the next 15 years (that is, 400 MW over 15 years). The practical options available are:

1) to construct a 100 km, 220 kV double-circuit line immediately, to cater for the first 200 MW of generation and another 100 km- 220kV double circuit line in ten years, to cater for the second 200 MW of generation; or,

2) construct a 100 km 400 kV double circuit line immediately to cater for all 400 MW of generation.

20. The least-cost option is identified by summing and comparing the present values of the costs of constructing and operating the assets over their lives, as shown in Table 1 (note the currency used in these examples is Indian Rupees [INR]). In this example, Option 2 is the least-cost option even though its initial capital cost is higher than Option 1.

Table 1: Identification of Least Cost Option for Example 1

Option 1: 220 kV												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Capital	1,512.0	-	-	-	-	-	-	-	-	-	2,462.9	0.0
O&M	22.7	23.8	25	26.3	27.6	28.9	30.4	31.9	33.5	35.2	97.1	102.0
Losses	6.8	6.8	6.8	6.8	6.8	27.3	27.3	27.3	27.3	27.3	34.1	34.1
Total	1,541.50	30.6	31.8	33.1	34.4	56.2	57.7	59.2	60.8	62.4	2,594.1	136.0
Present Values (20 years)												
PV (Capital)	2,287.5											
PV (O&M)	419.2											
PV (Losses)	171.5											
PV (Total)	**2,878.3**											
Option 2: 400 kV												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Capital	2,043.0	-	-	-	-	-	-	-	-	-	-	-
O&M	30.6	32.2	33.8	35.5	37.2	39.1	41.1	43.1	45.3	47.5	49.9	52.4
Losses	1.7	1.7	1.7	1.7	1.7	6.7	6.7	6.7	6.7	6.7	15.0	15.0
Total	2,075.3	32.3	32.3	32.3	32.3	37.3	37.3	37.3	37.3	37.3	45.7	67.5
Present Values (20 years)												
PV (Capital)	2,043.0											
PV (O&M)	343.1											
PV (Losses)	62.9											
PV (Total)	**2,448.9**											

Note: All figures in million INR. Main assumptions were: capital cost of 220kV line = INR 15.1 million/km; cost of 400kV line = INR 19.5 million/km; incremental cost to a generator for a 400kV line bay (e.g. connection) over a 220kV line bay = INR 90 million; cost of losses = INR 3.5 per kWh; weighted average cost of capital = 12.3% (in nominal pre-tax terms), which is also used as the discount rate for calculating present value (PV); operation and maintenance cost = 1.5% of capital cost per annum; average capacity factor (or plant factor) = 50%; capital cash flows assumed to occur at the start of year and others at the end of year. Income and other turnover taxes were ignored.

Example 2

21. Table 2 shows an approximation of the tariff calculation using a standard ARR approach for each of the options used in Example 1.

22. The table demonstrates that, even though Option 2 is the least cost option, it would impose a significant tariff premium (via a higher annual total revenue requirement) over Option 1 for the first 10 years for which no incremental benefit accrues to users of the asset. In later years, Option 2 results in a lower tariff for users of the asset, and in present value terms the tariff paid is roughly equivalent over 20 years under the two options.

Table 2: Calculation of ARR

Option 1: 220 kV												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Interest on loan	118.7	112.6	106.5	100.4	94.3	88.2	82.2	76.1	70	63.9	251.1	235.1
Depreciation (incl. ADD)	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	139.1	139.1
O&M	22.7	23.8	25	26.3	27.6	28.9	30.4	31.9	33.5	35.2	97.1	102.0
Interest on working capital	6.9	6.9	6.9	6.9	6.9	7	7	7	7.1	7.1	20.9	21.1
Return on equity	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	166.9	166.9
Total revenue requirement	264.7	259.7	254.8	250	245.2	240.6	236	231.4	227	222.7	675.2	664.2
Price per MW	2.65	2.60	2.55	2.50	2.45	1.20	1.18	1.16	1.14	1.11	2.25	2.21
Option 2: 400 kV												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Interest on loan	160.3	152.1	143.9	135.7	127.5	119.2	111	102.8	94.6	86.3	78.1	69.9
Depreciation (incl. ADD)	71.5	71.5	71.5	71.5	71.5	71.5	71.5	71.5	71.5	71.5	71.5	71.5
O&M	30.6	32.2	33.8	35.5	37.2	39.1	41.1	43.1	45.3	47.5	49.9	52.4
Interest on working capital	9.3	9.3	9.3	9.3	9.4	9.4	9.4	9.5	9.6	9.7	9.7	9.8
Return on equity	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8
Total revenue requirement	357.6	350.9	344.3	337.8	331.4	325.1	318.8	312.7	306.7	300.8	295.1	289.5
Price per MW	3.58	3.51	3.44	3.38	3.31	1.63	1.59	1.56	1.53	1.50	0.98	0.96
Premium (discount) under Option 2	**92.9**	**91.2**	**89.5**	**87.8**	**86.1**	**84.5**	**82.9**	**81.3**	**79.7**	**78.2**	**-380.1**	**-374.8**

Note: All figures in million INR.

23. Under the ARR approach, even though an investment is demonstrably least-cost, it does not necessarily provide the best pricing outcome for all transmission customers over all time periods. In particular, initial transmission customers may be faced with a very high transmission tariff with an expectation (but not a guarantee) that tariffs will reduce over time as asset utilization increases. They are thus bearing the brunt of the volume uptake risk. This may not be equitable and could ultimately discourage investment. A tariff regime that discourages efficient investment is undesirable.

24. This example thus highlights that the least-cost option does not necessarily represent the best pricing outcome for all transmission customers over all time periods, and demonstrates the way in which initial customers bear future volume uptake risk. This high initial price (or volume-related price risk) may prove to be unacceptable for potential open access customers, leading them to invest elsewhere.

E. Regulatory Issue of Real Options

25. A more recent regulatory consideration, which has particular relevance to the fundamental dilemma mentioned above, is the concept of real options in investment decision making. For example, in the above example, though option 2 is the least-cost option, option 1 has the advantage of deferring a portion of the investment until a later date, at which time more information may be known about the quantum of future generation capacity, and thus lowering the volume uptake risk.

<u>Example 3</u>

26. In revising option 1 above, option 1b below, assumes at the time to build the second line, it is apparent that only 100 MW of additional generation capacity will come on line instead of the 200 MW originally envisaged. The second investment is thus reduced to a 220 kV single circuit line rather than a double circuit line. As an additional scenario option, 1c assumes that after ten

years, there is no additional generation capacity and as such, no second investment is required. For both scenarios shown in Table 3, the ability to defer a portion of investment until further information is available, lowers the cost and eliminates the volume uptake risk. Note however, that option 1b still has a higher present value cost than building the 400 kV line in option 2.

Table 3: Option 1 Revised for Additional Information

Option 1b: 220 kV line constructed upfront, but 2nd line reduced to single circuit zebra line												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Capital	1,512.0	-	-	-	-	-	-	-	-	-	1,600.9	-
O&M	22.7	23.8	25.0	26.3	27.6	28.9	30.4	31.9	33.5	35.2	76.1	79.9
Losses	6.8	6.8	6.8	6.8	6.8	27.3	27.3	27.3	27.3	27.3	34.1	34.1
Total	1,541.5	30.6	31.8	33.1	34.4	56.2	57.7	59.2	60.8	62.4	1,711.0	113.9
Present Values (20 years)												
PV (Capital)	2,016.1											
PV (O&M)	361.4											
PV (Losses)	151.3											
PV (Total)	**2,528.8**											
Option 1c: 220 kV line constructed upfront, no second line												
Year =>	1	2	3	4	5	6	7	8	9	10	11	12
Capital	1,512.0	-	-	-	-	-	-	-	-	-	-	-
O&M	22.7	23.8	25.0	26.3	27.6	28.9	30.4	31.9	33.5	35.2	36.9	38.8
Losses	6.8	6.8	6.8	6.8	6.8	27.3	27.3	27.3	27.3	27.3	27.3	27.3
Total	1,541.5	30.6	31.8	33.1	34.4	56.2	57.7	59.2	60.8	62.4	64.2	66.0
Present Values (20 years)												
PV (Capital)	1,512.0											
PV (O&M)	253.9											
PV (Losses)	136.9											
PV (Total)	**1,902.8**											

Note: Option 1b assumes a 220 kV single circuit zebra line would cost about 65% of the originally intended double circuit line.

27. To carry this further, assume that a system planner might ascribe probabilities to the three possible outcomes, that is: (i) a 200 MW capacity second line, (ii) a 100 MW capacity second line, and (iii) no second line. Table 4 shows a probability-weighted present value of costs. The value of the optionality depends on the probability ascribed to the outcomes (and, in a real options analysis, the extent to which management can respond to new information as it comes to light over time). Given the probabilities used in Table 4, the planner would likely still proceed with option 2, the single upfront 400 kV line investment, as it remains least-cost.

Table 4: Probability Weighted Present Value of Costs

Outcome	**Probability**	**Weighted PV**
Option 1: 200 MW capacity 2nd line required	40%	1,151.3
Option 1b: 100 MW capacity 2nd line required	40%	1,011.5
Option 1c: No 2nd linerequired	20%	380.6
		2,543.4

28. Another aspect not considered above are potential additional costs associated with deferring investment and preserving flexibility. In this example, there may be upfront costs

incurred to secure the right-of-way for the second line, plus ongoing payments to keep the right-of-way (and perhaps land use consents) alive. The extent to which the regulator allows these costs to be passed through in the tariff, then becomes an issue.[7] Note, however, that these examples are deliberately simplistic.

29. A proper consideration of optionality would use real options analysis to properly assess the "option value" that would be considered a benefit that is factored into the cost considerations that were the focus of this example. In a consultation note, the Office of Gas and Electricity Markets (OFGEM) of the United Kingdom, recognized the value of optionality, and has stated:

> The anticipated de-carbonization of the UK energy sector means that there is significant uncertainty surrounding the way energy will be produced, consumed and transported in the UK. The level of uncertainty means that there is significant value to investment options which provide flexibility[8]

30. Australia has introduced the concept of real options in recent years in evaluating transmission investments, particularly given the uncertainty of future generation and how various generation development scenarios can affect the calculated net benefits of the proposed transmission investment. One cited example, similar to the one above, is the choice of investment to a) build a shared network beyond present needs (thus taking into account anticipated future generation additions), b) building the shared network only for present needs, or c) building the shared network to meet present needs but with the ability to expand quickly at lower cost (such as building larger towers for more or larger lines in the future). It is pointed out that example (c) may be more beneficial than option (a) because of its optionality from deferring certain investments until uncertainty is reduced.[9]

III. INDIAN CONTEXT

31. Consistent with standard tariff methodology, the Central Electricity Regulatory Commission (CERC), Government of India, formally notified its regulations in March 2004 for tariff determination of interstate transmission assets using the ARR approach.[10] This approach allows cost recovery including debt repayment (the "cost" component of ARR) and allowing a 14% return on equity up to a maximum of 30% of assets' initial capital cost (the "plus" portion).[11] Until 2010, costs were apportioned to transmission users on a regional postage stamp basis, meaning that all users of common regional transmission networks paid the same price per MW of allocated transmission capacity. However, with increasing inter-regional power flows, inter-regional allocation of generating capacity, and short-term transactions over regional and inter-regional lines, issues of allocative economic inefficiency arose. Without altering the cost recovery of ARR by transmission providers, CERC has made several modifications to how these costs are allocated among system beneficiaries in recent years. Commencing 1 January 2011, it substantially revised its approach to cost allocation by adopting zonal pricing based on

[7] Extensions of this analysis could consider engineering solutions such as only stringing one circuit of the 400 kV line (although that has security implications) or using a smaller conductor and increasing capacity later using reactive compensation.

[8] Office of Gas and Electricity Markets, 1 June 2012. *Real Options and Investment Decision Making*. London. Pg 9.

[9] Australian Energy Market Commission, 25 June 2009. *Regulatory Investment Test for Transmission, Final Rule Determination*. Sydney, pp. 41-42.

[10] Intra-state transmission tariffs set by state level independent regulators also reflect the ARR approach as guided by CERC.

[11] Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004.

a point of connection method of sharing inter-state transmission service costs, replacing the regional postage stamp system. Costs are now sensitive to distance, direction and related to quantum of power flow and are allocated between generators and end-users.[12]

A. The Himachal Pradesh Case

32. Himachal Pradesh, a small mountainous state with a population of slightly over 6.8 million, has abundant water resources in the five major rivers flowing through the state from the western Himalayas. The hydropower generation potential of Himachal Pradesh is about 23,000 MW—about one-fourth of the total hydropower potential of India. Installed hydropower capacity in Himachal Pradesh was 6,673 MW as of June 2011. In its Hydropower Policy, 2007,[13] the government of Himachal Pradesh targets its comparative advantage in hydropower with the goal to become the "hydropower state" of the country.

33. The state's objective of encouraging investment in hydropower generation also requires building out the transmission infrastructure so that the additional hydropower can be efficiently transmitted within and outside the state. The state transmission utility, H.P. Power Transmission Corporation Ltd. (HPPTCL) has prepared a power system master plan to articulate transmission network expansion.[14] This master plan not only considers immediate hydropower plant connection requirements, but also expected future requirements in each of state's five major river basins. The plan, endorsed by India's Central Electricity Authority (CEA), provides a sound basis for investment in transmission facilities, and is expected to engender confidence among existing and potential private hydropower developers that sufficient transmission capacity will be available to evacuate power from hydropower facilities to markets outside of Himachal Pradesh.

34. This approach replaces earlier plans where often, each hydropower station would have its own dedicated transmission line for evacuation of power, resulting in duplication of assets, crowded river valleys and poor environmental outcomes. In developing the updated master plan, HPPTCL's approach has been to eliminate these multiple parallel transmission lines as far as possible by proposing secondary pooling points that are interconnections with the main arteries of the transmission infrastructure. This is particularly necessary in Himachal Pradesh as there is the additional complication of transmission corridor congestion due to the mountainous terrain and limited land availability, with heightened environmental and social impacts due to the physical space constraints. These (transmission corridor) space constraints and environmental, social and land use concerns, combined with the least-cost analysis, concluded that building surplus capacity was necessary.[15]

35. Specifically in Himachal Pradesh, it is likely that the transmission master plan will result in localized cases of significant (but economically efficient) spare capacity for a period of five to ten years. Furthermore, a flexible approach introduced by option 1 and its variants shown in

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[12] Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010.

[13] Government of Himachal Pradesh. 2007. *Hydro Power Policy, 2007.* Shimla.

[14] ADB. 2008. *India: Capacity Building for Himachal Pradesh Power Sector Agencies*. Manila. (This technical assistance, TA 7181-IND, funded the master plan study, and also funded a study on the tariff matters applicable to Himachal Pradesh explained in this working paper. For the tariff study, some input and review by Mr. Tony Evans and review by Mr. Geoff Stott is gratefully acknowledged.)

[15] One consideration was to build towers to accommodate larger capacity with space to string extra lines in the future, but the majority of the costs would still be borne upfront so that it did not solve the problem of bearing costs now for future capacity. Also, due to the remote, mountainous terrain, the active line would likely need to be shut down for considerable periods while stringing the additional line, which would impose significant costs as existing independent hydropower projects already connected would be unable to wheel their power.

Example 3 is not possible in many locations due to narrow valleys with no space for multiple lines. As shown in example 2 above, if these costs are borne by earlier generators, the high initial price could discourage them from investing. In India, this would be at odds with the National Electricity Policy's directive to signal efficient choice in the location of generating capacity for optimum utilization of generation resources. India's National Electricity Policy states the following:

> To facilitate orderly growth and development of the power sector and also for secure and reliable operation of the grid, adequate margins in transmission system should be created. The transmission capacity would be planned and built to cater to both the redundancy levels and margins keeping in view international standards and practices. A well planned and strong transmission system will ensure not only optimal utilisation of transmission capacities but also of generation facilities and would facilitate achieving ultimate objective of cost effective delivery of power. [16]

36. That is, the National Electricity Policy recognizes it is economically efficient to build a certain amount of surplus capacity now for future users, and that failure to address the issues of prudent capacity margin, goes against the interest of long-term cost effective power supply.

B. The Rajasthan Case

37. Geographically, Rajasthan is India's largest state, and has India's highest solar irradiation, particularly in the far western, Thar Desert region. Installed generating capacity was 4,702 MW as of March 2009 with about 1,600 MW of wind power and 200 MW of solar power additions expected by the end of 2012. The total population is about 56.5 million people.

38. In 2010, the Government of India launched the Jawaharlal Nehru National Solar Mission (JNNSM), to create an enabling framework for the deployment of 20,000 MW of solar power across India by 2022. Rajasthan has adopted its own Solar Policy in 2011 and draft Wind Policy in 2012. The Rajasthan Electricity Regulatory Commission (RERC) has set renewable purchase obligations for the utilities in the state.[17] Private generators have also set up wind and solar projects to supply power purchasers outside Rajasthan through long term contracts and through India's renewable energy certificate mechanism.[18] The state intends to add 5,700 MW of private sector-developed renewable energy capacity over 2012-2017, which includes solar projects awarded under the JNNSM. Over 4,200 MW of this new capacity is expected in Western Rajasthan, including 250 MW at the first phase of the solar park, being developed in Bhadla by the Rajasthan Renewable Energy Corporation (RREC).[19]

39. The Rajasthan Rajya Vidyut Prasaran Nigam Limited (RRVPNL), the state transmission licensee of Rajasthan, is responsible for evacuating all electricity produced in the state, including renewable energy produced in the solar and wind parks. They are planning

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[16] Government of India. 2005. National Electricity Policy. New Delhi.

[17] The utilities in Rajasthan are mandated to procure 5.7% of their overall power requirement from wind and 1.0% from solar power projects by 2013-2014.

[18] This market-based government program enables qualifying renewable energy generators to earn a renewable energy certificate (REC) for each MWh of power generated. RECs are then tradable and purchasers can satisfy their renewable purchase obligations through purchasing RECs in lieu of purchasing renewable energy directly.

[19] RREC is the nodal agency responsible for developing renewable energy in Rajasthan, including the Bhadla solar park. They will coordinate with the state government to give land access to project developers. The bidding process for private sector investors will be handled by a committee of secretaries supported by RREC.

transmission system investments over the next five years to accommodate an additional 2,000 MW of wind, and 3,700 MW of solar power. As most of this capacity is expected to come from private sector developers, ensuring adequate transmission capacity and reasonable connectivity costs is essential to attract the requisite investment to realize the state's considerable renewable energy potential.

40. As in Himachal Pradesh, it is likely that the proposed transmission investments will initially result in spare capacity. This is inevitable as developers will be reluctant to invest based on promised, rather than existing, transmission capacity. This then creates volume uptake risk if the wind/solar generation does not fully eventuate. Due to the long distances involved, it would be a lower cost option to build fewer, larger high-voltage lines to serve as main network corridors for moving power across and out of the state. However, unlike Himachal Pradesh's narrow valleys and limited space for transmission lines, Rajasthan's open desert terrain could allow parallel lines to be built at a later date, or could include larger towers capable of handling larger or additional lines, which could be a means of managing this risk. The cost issues faced by the state are that the distances in Rajasthan are much longer in order to reach out-of-state markets as compared to Himachal Pradesh. Furthermore, the variability and low capacity factors of solar and wind power relative to hydropower, requires transmission capacity to accommodate peak production, leaving unutilized capacity for the non-peak generation periods and thus higher costs on a per MWh basis.[20] How best to manage these risks and allocate these costs is an important matter for the state.

IV. APPROACHES IN OTHER JURISDICTIONS

41. This section provides a discussion of solutions to problems of spare capacity, cost recovery timing and intergenerational equity in other jurisdictions, including other utility sectors.

A. The Generic Approach – Manipulating the Depreciation Building Block

42. The most common mechanism adopted by regulators to manage prices in order to ensure that prices and revenues are appropriate over time, is to manipulate the depreciation component of the aggregate revenue requirement. Accelerated depreciation may be allowed to reduce risks to network businesses when assets are used to supply a load or generator with limited economic life. Deferred depreciation may be required to ensure that future customers pay an appropriate tariff for use of network being built now.

43. Unfortunately it is not possible to directly apply this methodology in Himachal Pradesh because economic regulation uses cash flow building blocks (rather than economic and/or accounting ones). In Australia, New Zealand, the United Kingdom, the United States and Western Europe, economic regulators typically calculate allowed tariff revenue using capital building blocks of "return on investment" and "return of investment" or "depreciation". It is this depreciation building block that regulators can manipulate to change the amount of revenue recovered over time. By comparison, in Himachal Pradesh, the allowed revenue is calculated using capital building blocks of "return on equity" and "depreciation", where depreciation is the larger of economic depreciation (on a straight-line basis) and (of) loan repayments (up to an annual maximum of 10% of the book value of debt, and only where cumulative repayment

[20] The tendency for stronger wind speeds at night partially offsets this issue, as peak wind generation would occur when solar generation is idle.

exceeds cumulative depreciation). In almost all cases for new assets, “depreciation” will reflect loan repayments rather than economic depreciation.

44. The applicable approach for Himachal Pradesh would be to manage the return on equity and loan repayment cash flows, either virtually in the regulated accounts, or physically by negotiating deferred returns with equity holders and debt providers. In practice, lenders would likely not agree to defer repayment. This leaves the government of Himachal Pradesh as the sole equity holder in the state transmission utility and the only party able to defer recovery of its return on investment.

45. The mechanisms to achieve intergenerational equity discussed in Section V below (setting a long-term constant tariff, or establishing a spare capacity “account”) effectively defer returns to equity holders. While deferred return on equity and loan repayments may affect the investment risk assessment of debt and equity providers, deferred payments do not necessarily mean that the debt or equity holder has accepted increased repayment risk (for example volume uptake risk). Volume uptake risk should be separately handled and allocated to the most appropriate party, taking into considerations other aspects of the regulatory regime.

B. Australian Bulk Water – 20 year Pricing Model

46. The Gladstone Area Water Board (GAWB) in Queensland, Australia is a bulk supplier of water. Dams have a very long life (greater than 200 years) and are efficiently built in very large increments, so at the time of capacity augmentation, there is a large amount of spare capacity.

47. The Queensland Competition Authority (QCA), the economic regulator for GAWB) concluded that the optimum method for pricing bulk water supply services with significant spare capacity was to set a constant real price over 20 years (approximately equal to the capacity uptake period). The QCA sets a price so that the expected present value of revenue equals the expected present value of economic costs over the pricing horizon. (A detailed example is shown in example 4 in Section V.)

C. Australian Gas Industry – Speculative Investment Account

48. Regulation of many gas pipeline companies in Australia includes the concept of “speculative investment.”[21] A speculative investment is a capacity augmentation that is greater than the capacity needed to meet contracted demand (or short-term forecast demand).

49. The assets required to meet the contract demand are collectively termed the Regulatory Asset Base (RAB). Prices are set to provide the gas pipeline company with a regulated rate of return on the RAB. Speculative investment is excluded from the RAB and assigned to a speculative investment account. The speculative investment account earns interest (capitalized in the account) at a regulated rate.

50. When new customers take up the capacity funded by the speculative investment, costs, including interest earned, are transferred from the speculative investment account to the RAB (subject to regulatory tests for efficiency). Prices are then reset, including both the transferred supply capacity and new demand.

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[21] The West Australian Electricity code also included a provision for speculative investment (reference Section 6.58 to 6.60 of the Electricity Networks Access Code 2004).

D. United Kingdom Transmission Extension

51. To allow the connection of a large number of renewable generators to the U.K. national electricity grid required significant augmentations and extensions into remote areas. Several problems were identified with the pre-existing regulatory and commercial arrangements. Most significantly:

- transmission companies were unwilling to undertake such large increments when demand uptake was uncertain; and
- the transmission pricing regime would have resulted in very high charges in the north of Scotland and west of Wales (but the renewable generation was required to meet national renewable targets rather than regional demand).

52. To facilitate timely investment, the relevant economic regulator (OFGEM) allowed the transmission business to immediately recover preparatory works from the general customer base. Further investment was to be considered at future price reviews.[22]

53. Another government initiative is the “Connect and Manage” framework introduced in 2010 after the prior “Interim Connect and Manage” regime from 2009. Under existing rules, generators could not connect until all necessary required grid upgrades beyond the actual physical connection were completed. This caused bottlenecks for renewable energy projects with long waits for grid connectivity and was thus hampering the United Kingdom’s renewable energy generation targets. Under this new regime, generators could apply for connection before any wider grid reinforcements were completed. Once connected, any constraint costs caused by the early connections are to be socialized across all consumers, including any subsequent wider network upgrade work.[23]

E. Offshore Transmission

54. The United Kingdom surpassed Denmark in 2008 to become the world leader in installed capacity of offshore wind power generation. A recent study predicts that offshore wind power could reach 18 GW by 2020 and supply up to 17% of the U.K. power supplies.[24] The United Kingdom authorities recognize that offshore wind project development poses particular challenges in relation to transmission system investments and in ways is more analogous to the situation faced by Himachal Pradesh and Rajasthan than some of the other cases.

55. To facilitate investment, OFGEM and the U.K. Government’s Department of Energy and Climate Change established a regulatory framework in 2009, called the Offshore Transmission regime, in order to ensure offshore wind farms are economically connected to the onshore network. This includes competitive tenders for transmission asset construction and operation combined with asset-based regulation within the U.K.’s existing regulatory framework. The authorities also commissioned an analysis on the most cost effective approach. Interestingly, the conclusions were similar to those reached in Himachal Pradesh regarding the least-cost option of an integrated approach; that “instead of building individual connections for each

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[22] The Transmission Investment in Renewable Generation (TIRG) mechanism introduced in 2004 and the later “Revenue = Incentives + Innovation + Outputs” or (RIIO) mechanism identified specific investments required for renewable energy and allowed cost recovery through their existing transmission pricing methodology.

[23] OFGEM, 30 March 2011. *First Report from OFGEM on Monitoring the “Connect and Manage” Electricity Grid Access Regime.* London.

[24] RenewableUK (formerly British Wind Energy Association). http://www.bwea.com/offshore/.

development, and separate reinforcements of the onshore network where necessary, they could be interlinked to lower the overall construction and operating costs."[25] The analysis suggested that a coordinated approach could reduce the cost of offshore connections by 8-15% (£0.5-3.5 billion)[26] (and would thus contribute to the government's target of reducing the overall cost of offshore wind.

56. Recognizing that a competitive tender process and a coordinated investment approach would lower costs and thus lessen the burden on ratepayers, the question remains as to how to share the cost burden. A separate review of the general transmission pricing regime, labeled Project Transmit, addressed issues of pricing the investment required for renewable generation. The existing Investment Cost Relating Pricing (ICRP) methodology charges generators more according to how far they are located from the load. This places a large cost burden on remote wind projects including offshore projects. Various alternative approaches have been reviewed, including socialization, and an OFGEM favored, modified form of ICRP that would discount this cost burden for intermittent sources of generation (namely wind).[27]

57. While the amount of capacity forecast to be added is large, in the context of the national electricity grid, the amount of spare capacity is not expected to be significant. As evidenced by OFGEM's careful consideration of various options with varying opinions among stakeholders, finding the balance between promoting renewable and allocating the additional costs is a complex undertaking. The authors know of no measures specifically put in place to deal with intergenerational equity issues.

F. Australian Electricity Industry – Scale Efficient Network Extensions (SENE)

58. Australia faced a similar problem of extending the electricity system to facilitate connection of renewable generation. In February 2010, the Australian Ministerial Council on Energy requested that the Australian Energy Market Commission (AEMC) investigated a change to the National Electricity Rules to ensure that scale efficient network extensions were constructed.[28]

59. The AEMC characterized the problem of constructing scale efficient networks as follows:

> Historically, the scale of investment in generation has matched the scale of the transmission or distribution investment that is required to facilitate connection. Networks have developed to meet the requirements of these generators.
>
> The characteristics of the generation that is likely to connect over the next decade differ in a number of respects, such as:
>
> - some of the lowest cost sources of generation are located remote from the existing networks; and
> - much of the new generation that is likely to seek connection is relatively small compared to the "lumpy" network investment required to connect it.

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[25] OFGEM, 29 February 2012. *Submission from the Office of the Gas and Electricity Markets*, London.
[26] Ibid.
[27] OFGEM, 4 May 2012. *Information Note: OFGEM Takes Next Step Towards New Transmission Charging Structure.* London.
[28] Note: The original SENE proposal was ultimately not accepted in its entirety, although some of its concepts have been captured in the updated Regulatory Investment Test for Transmission.

> This implies that there are likely to be efficiencies from coordinating such connections, particularly where new generation clusters around an energy source such as wind or gas. Connecting generators in a way that will minimise expected total system costs will require investment that is more forward looking.
>
> However, achieving coordinated connections is likely to prove challenging under the existing frameworks. This is because no entity currently has an incentive to underwrite the risks of building additional network capacity in anticipation of future generation. The nature of the broader framework does not encourage or reward speculative building of transmission assets, either by [transmission companies] or generators. Uncertainty regarding the likelihood of generator entry and reluctance on the part of generators to tie their projects to the time frames of their competitors further hinders efficient connection outcomes. [29]

60. This is directly analogous to the issue facing Himachal Pradesh. Indeed, the above quotation would be a reasonable description of the situation in Himachal Pradesh if the words “wind or gas” were replaced with “river valleys with hydro-electric potential”.

61. The AEMC developed criteria for assessing a regulatory framework that facilitated efficient network extensions. The objective of the framework is to allow the efficient connection of multiple generators with multiple owners in proximate areas over time and to charge users an efficient price for that service. Specifically, the AEMC developed the following assessment criteria:

1. Generators are able to connect in a timely manner. This is at risk where large volumes of connection applications and multiple connection applications in the same area are anticipated. This also implies that any process for identifying, planning and constructing an efficient scale network extension should not be at risk of unnecessary or lengthy delays, which in turn, may delay generation investment.

2. Generators can be connected with efficiently sized and located assets, taking into account current and likely future generation, to allow scale economies to be captured. This will occur where the framework provides appropriate mechanisms or incentives that allow capacity to be built in advance of expected future connections where it is efficient to do so. The potential scope of the efficiency gains will depend on several factors including the number of potential generators, their geographical spread and their distance from the existing network.

3. Generators must face efficient cost signals to ensure that they make efficient locational decisions.

4. The framework should not be unnecessarily complex or burdensome. Where complexity is unavoidable, it should be commensurate with the magnitude of the problem to be solved.

5. Stranded asset risk is appropriately managed.

[29] AEMC, *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010, Options Paper*, September 2010, pg. iii.

62. In Himachal Pradesh, the transmission power system master plan largely addresses criteria 1 and 2. Point 3 is consistent with the National Electricity Policy. The remaining criteria (4 and 5) are the subject of this working paper.

63. Of particular relevance to this report is the recommended pricing arrangement for scale network extensions. In its Rule Determination for the pricing of prescribed transmission services, the AEMC noted:

> In order to promote allocative efficiency, transmission prices should generally be set on a “causer pays” basis where possible. This means that where transmission costs are incurred following a direct request by (or agreement with) a particular network user or users, those user(s) should be required to pay the relevant costs. [30]

64. That is, generators are required to pay for extensions of the transmission system necessary to connect those generators.

65. However, in order to provide certainty to transmission companies that the costs of efficient network extensions will be recovered, the AEMC proposed that customers should underwrite the volume uptake risk. This was considered reasonable since customers should be the ultimate beneficiaries from arrangements that facilitate the most efficient connection of generation.

66. Charges would be set so transmission companies recover their efficient costs, including a return on their investments. Generators would be charged an average cost for capacity on a per MW basis. Initially, the revenue recovered from generators would be less than the transmission company’s required revenue from the assets and the AEMC recommended that the revenue shortfall be recovered from “loads” (that is, from end-use customers). In other words, the transmission company would still receive its full ARR every year by “borrowing” revenue from loads and repaying the revenue (with interest) at some point in the future once generators take up the additional network capacity. Loads would also be exposed to costs if generators connect later than forecast (or do not connect at all), but would benefit if generators connect early. Although loads would initially fund the spare capacity, they would expect to be repaid.

67. The AEMC considered that it was appropriate for loads to partially fund the spare capacity and bear the volume uptake risk because loads ultimately benefit from the economies of scale associated with efficient investment.

V. TRANSMISSION PRICING OPTIONS

68. This section proposes possible solutions for transmission pricing and regulation based on the examples mentioned above.

[30] AEMC, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22, Rule Determination*, December 2006, page 20.

Long-Term Price Modeling

69. This approach is based on the model adopted by the Queensland Competition Authority for GAWB as discussed above.

70. The solution would involve setting a constant real price so that the present value of revenues equals the present value of costs over a pre-defined period. A period of 20 years is used by the QCA, but modeled here are ten year, 15-year and 20-year periods, for the purposes of this working paper.

Example 4

71. Using Option 2 from Example 1, the present value of the ARR for each of ten, 15 and 20 years were determined. The present value of the ARR in each case was then divided by the present value of the forecast power flow to calculate a single real price (in INR million per MW) for the asset, as shown in Table 5 (Appendix 1). The table demonstrates that, even though forecast revenue does not match ARR in every year, ARR and forecast revenue are equivalent in present value terms over the period.

72. Under this approach, benefits of future demand growth (and economies of scale in constructing the long-term optimal solution) are available to existing customers. That is, initial prices are generally lower than those that would have been charged had a smaller (economically sub-optimal) capacity increment been constructed. Also, the tariff is typically stable over time.

73. The methodology is simple to implement and is consistent with periodic (annual, three-yearly or five-yearly) tariff reviews. It does, however, impose a significant demand- and expense- forecasting burden on the regulated entity and the regulator (particularly in an Indian context, where forecasts are typically for no more than three years). In general, the forecast period used for long-term price modeling should at least allow for full utilization of the asset (in this example, the price is lowest for the 20-year forecast case [INR 1.5 million per MW] due to an increase in power flow to 400 MW in years 16-20).

74. One potential problem with this approach may arise where the new capacity is a large proportion of the total regulated asset base and where there is significant initial spare capacity, as is likely to be the case for HPPTCL, and to a lesser extent, for Rajasthan. This is demonstrated with Example 3, which is essentially a one-asset system. In the initial years, the cash flow received from the tariff is less than the amount needed to fund interest, operating and maintenance expenses.

75. This problem would not arise if the spare capacity was not a large proportion of the asset base because sufficient cash would be generated from other assets to cover cash costs.

76. To ensure that the transmission company recovers sufficient tariff revenue to meet cash outflows, several modifications to a simple long-term tariff are possible:

- including a higher proportion of equity funding;

- structuring financial arrangements to have lower initial repayment requirements (for example a 5-year repayment holiday); and

- changing the tariff from a constant real tariff to a reducing tariff (although this may re-introduce the problems of intergenerational equity that the pricing arrangement is attempting to mitigate).

77. Example 5 below shows that by increasing equity funding from 30% to 54% in the ten-year forecast case, the revenue recovered by tariffs exceeds interest, operating and maintenance expenses every year. Note that this is not a conceivable option in any deregulated or investor-owned power sector, as equity financing is a more expensive form of financing, and making a larger equity investment in the face of stranded transmission asset risk is most likely not commercially feasible.[31]

Example 5

78. Using Option 2 from Example 1, a long-term tariff was determined for a 10-year forecast period (as per Example 3), but with equity contribution increased from 30% to 54%.

79. Table 6 shows the tariff calculation. With the increase in equity, revenue is sufficient in every year to meet cash costs (that is, debt service and operations and maintenance).

Table 6: Calculation of Long-Term Tariff (INR million)

Year =>	1	2	3	4	5	6	7	8	9	10
Total revenue requirement (a)	358.3	354.5	350.9	347.2	343.7	340.3	337	333.8	330.7	327.8
Forecast power flow (MW) (b)	100	100	100	100	100	200	200	200	200	200
PV (a)	1,933.00									
PV (b) (MW)	999.9									
Revenue per MW	2	2.1	2.2	2.3	2.5	2.6	2.7	2.9	3	3.1
Revenue (c)	203	213.1	223.8	235	246.7	518.2	544.1	571.3	599.8	629.8
PV (c)	1,933.00									
Minimum cash requirement										
Debt service	172.3	167	161.7	156.4	151.2	145.9	140.6	135.4	130.1	124.9
O&M	30.6	32.2	33.8	35.5	37.2	39.1	41.1	43.1	45.3	47.5
Total	203	199.2	195.5	191.9	188.4	185	181.7	178.5	175.4	172.4
Cash surplus/(shortfall)	0	13.9	28.3	43.1	58.3	333.2	362.4	392.8	424.4	457.4

80. As highlighted above, the appropriateness and implications of an increase in equity contribution above the currently prescribed maximum of 30% needs to be considered. Firstly, it can be argued that because the government of Himachal Pradesh is in a position to influence transmission capacity uptake through its hydropower and industry approval processes and its ability to attract external investment, it should, as sole equity holder in HPPTCL, be willing to accept deferral of its investment return until capacity utilization increases. Moreover, from an economic viewpoint, because “society” benefits from the implementation of the least- cost option (rather than more expensive options), the government (as a proxy for “society”) should be willing to intervene where the transmission company would have selected more expensive options.[32] Secondly, since the cost of equity is higher than the cost of debt, an increase in equity funding results in an increase in price for customers. However, in this case, the increase in price is modest since there is only a 2.5 percentage point difference between (assumed) cost

[31] For example, private transmission businesses in Australia have not been too successful because they essentially relied disproportionately on risky spot prices.
[32] The state taking the volume uptake risk could be considered as a form of socializing this risk.

of debt and cost of equity. In addition, because of the higher equity contribution, lower interest rates on debt financing could possibly be negotiated which would serve to offset the cost increase attributable to higher equity contribution. Thirdly, the affordability of an increase in equity contribution for the government of Himachal Pradesh could be an issue, and the risk that assets are underutilized because the generation investment does not eventuate, requires analysis from the outset.

81. The following example shows how a portion of the proposed investment asset could be deferred until volume uptake risk has subsided.

Spare Capacity Investment Account Approach

82. This approach is based on the speculative investment provisions of the Australian Gas Rule discussed above. The solution would involve:

- setting the tariff based on the minimum capacity increment necessary to meet current demand; and
- assigning the cost of spare capacity to a spare capacity account.

83. When spare capacity is taken up, capacity would be added to the regulated asset base and the associated costs removed from the spare capacity account. Under this approach, ARR would be calculated on both the regulated asset base and the spare capacity account, but only the ARR on the regulated asset base would be charged to customers. The ARR on the spare capacity account would be accumulated and would be proportionately transferred to the regulated asset base as notional capacity transfers are made.

84. There are several ways to calculate the quantum of cost that is transferred from the spare capacity account to the regulated asset base. Two possible methods are:

- average incremental cost; and
- tranche notional incremental cost.

85. Under the “average incremental cost” method, each megawatt of connected generation capacity would result in the same cost (in present value terms) transferred into the regulated asset base. The advantages of this approach are that it is simple and yields the lowest initial tariff for a system and a stable tariff over time.

Example 6

86. Using Option 2 from Example 1, revenue allowance was determined for each year of a ten year forecast period (as per Example 3) using the average incremental cost approach. Total line capacity was assumed to be 400 MW, and therefore each generator was assumed to use 25% of the line’s total capacity. Table 5 (Appendix 2), shows the allowed revenue calculation for the first 16 years (at which point the entire asset is included in the Asset Base).

87. As discussed above, there may be cases when an averaged approach yields a tariff too low to recover sufficient revenue to meet the transmission company’s cash requirements. In that situation, a “tranche notional incremental cost” method may be useful. Under this approach, the

amount of cost transferred into the regulated asset base is based on the cost of notional network necessary to deliver the current connected capacity.

88. For example, for the hypothetical example under consideration, it is expected that a 400 kV supply will ultimately be required. The first connected generator might require only a single circuit 132 kV line to be constructed and so only the costs of a single circuit 132 kV line would be included in the regulated asset base (against which revenue would be earned by the transmission company). That is, the physical asset is 400 kV supply, but the cost of a notional 132 kV supply is added to the regulated asset base, with the additional costs of the physical supply added to the spare capacity account. Assume the second generator would require additional capacity, so that a notional double-circuit 132 kV line was required to connect both generators (that is, if both generators were connected at the same time, a single 132kV double circuit transmission line would have been adequate to connect them both). From the time the second generator connects, the cost of a double-circuit 132 kV line would be included in the regulated asset base and end-use customers would be charged for it (that is, the difference in cost between the hypothetical single-circuit and the hypothetical double-circuit is transferred from the spare capacity account to the regulated asset base). As subsequent generators connect, a new notional network is designed and costed for, and the incremental costs of the next tranche of capacity transferred from the spare capacity account to the regulated asset base.

89. Under the tranche notional incremental cost method, the tariff would initially be higher and it would reduce over time as generators accessed the available economies of scale. This approach has the advantage of recovering more revenue earlier while guaranteeing that customers pay no more than they would have paid if the minimum capacity increment necessary to meet current demand was constructed. The main disadvantage of this approach is administrative complexity (developing and pricing notional designs for each new connection).

90. Under either of the above approaches, it would be necessary to specify who takes the risk that forecast demand emerges and that spare capacity is ultimately utilized. Several options are possible, including:

- transmission customers;
- the transmission company; and
- state development agencies/state government (applicable only in a state-owned utility environment).

91. Regulators generally allocate risk to the party with the best ability to manage that risk and, when no party can manage the risk, to customers. Transmission companies cannot significantly influence take-up of transmission capacity and therefore it is not efficient that the demand risk is allocated to the transmission service provider. In the case of jurisdictions with state-owned utilities and where spare capacity is put in place for state development regions (i.e. to encourage establishment of industry), there is a case to argue that a state development agency should bear the risk of volume uptake (or the state government as a proxy for state development agencies). In other cases, the most efficient solution is for customers to directly bear the volume uptake risk, provided that the regulator is satisfied that the additional spare capacity is reasonable, with such determination made during the regulatory approval process. Australia’s RIT is an example of the forum for conducting this analysis.

92. The Australia Energy Market Commission (AEMC) commented as follows:

> Arguably the largest risk in the case of building additional network capacity in anticipation of future generation connections is that the forecast generation does not materialise, leaving a potentially costly stranded asset. It is this stranded asset risk that is particularly difficult to manage... There is tension between allocating this risk to those who are best placed to manage it and allowing efficient connection and pricing outcomes to be achieved.
>
> Consequently, the asset stranding risk may fall on customers as a means to balance efficient investment objectives with efficient risk allocation. In this instance, the Rules should provide appropriate regulatory oversight and other measures such that customer exposure is appropriately managed on their behalf. [33]

93. The spare capacity investment account solution has several disadvantages over the long-term price modeling solution, including:

- it is more administratively complex (requiring separate regulated asset base and spare capacity asset registers and the transfer of assets and costs between the registers); and

- notwithstanding a policy that loads should bear the risk of demand uptake, the transmission company might consider that there is a risk that the capacity associated with the spare capacity account could be permanently unrecoverable (which would make transmission service providers less willing to invest in optimal solutions with large initial spare capacity).

94. The second point above, could possibly be mitigated by all parties agreeing, before the investment is made, that any spare capacity remaining after a certain period of time (for example, at the midpoint of the asset's economic life) would be automatically transferred from the spare capacity account to the regulated asset base. This would effectively share the risk of stranded assets between the transmission company and end-use customers. Alternatively, in a context of state-owned utilities (such as India), the state government could shoulder this risk.

VI. CONCLUSION

95. This paper outlined transmission access pricing issues likely to arise when transmission assets are constructed with surplus capacity to allow for future growth in both supply and demand, meaning that new transmission assets would be designed to cater for probable loads in addition to committed ones, with surplus initial capacity an expected outcome.

96. The size of the transmission asset base is an important factor in assessing the magnitude of this issue. The ARR approach to transmission tariff setting provides reasonable price outcomes for customers across a large pool of assets (with prices set on a postage stamp basis) because surplus capacity tends to approximate a fixed proportion of total assets. This means that all customers pay a premium for surplus capacity that is more-or-less constant over

[33] AEMC, *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010, Options Paper*, September 2010, p17.

time. However, in a small asset base environment with an expectation of rapid growth in transmission requirements, issues of intergenerational equity may arise. To overcome issues of intergenerational equity in transmission pricing, modifications to the ARR approach are required.

97. Pricing frameworks used in other countries have been particularly relevant in addressing this issue, the simplest of which is simple manipulation of the depreciation building block of the ARR. Long-term price modeling produces a price that is fixed in real terms (that is, increases in line with inflation only) by forecasting expenditure and volume (load or power flow) for ten or more years and then determining the price that would deliver the required net present value of revenue over the forecast period. The spare capacity investment account approach requires operational assets to be notionally split between an “asset” account and a “surplus capacity investment” account, with ARR on the surplus capacity investment account accrued until the surplus capacity is required. Once the capacity is required, the relevant assets and their accrued ARR are transferred into the asset account and ARR is recovered on them. Long-term price modeling is easier to implement and administer than the spare capacity investment account approach. Both approaches have a potential drawback in that, when the proportion of surplus capacity relative to the asset and to the overall asset base is high, they may generate insufficient revenue to cover cash costs. However, minor modifications to both approaches can be made to avoid this problem.

98. Experiments with modifications of standard methodologies, socializing certain temporary congestion costs, and reducing overall costs via a coordinated, least-cost offshore grid solution are useful examples of how a regulator in an open, competitive electricity market continues to balance renewable energy targets with the basic cost-of-service methodology. Finally, providing revenue certainty to the transmission utility while sharing and shifting “volume uptake risk” and costs is another useful approach. All approaches are extensions of the simple ARR approach.

99. The purpose of this paper is to give an overview of various approaches used in different jurisdictions, but with similar and standard tariff pricing regimes. This can assist policy makers on how best to promote transmission system expansion to support renewable energy in their jurisdictions in an equitable and cost effective manner.

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Appendix 1

Table 5: Calculation of Long-Term Tariffs for Example 3 (INR million)

LONG-TERM PRICE MODELING																				
Year =>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Total revenue requirement (a)	357.6	350.9	344.3	337.8	331.4	325.1	318.8	312.7	306.7	300.8	295.1	289.5	284.0	278.6	273.5	268.4	263.6	258.9	254.4	250.1
Forecast power flow (MW) (b)	100	100	100	100	100	200	200	200	200	200	300	300	300	300	300	400	400	400	400	400
10-Year Forecast																				
PV (a) (years 1-10)	1,870.9																			
PV (b) (years 1-10)	999.9																			
Revenue per MW	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	2.9	3.0										
Revenue (c)	196.5	206.3	216.6	227.4	238.8	501.5	526.6	552.9	580.6	609.6										
PV (c)	1,871																			
15-Year Forecast																				
PV (a) (years 1-15)	2,192.8																			
PV (b) (years 1-15)	1,632.4																			
Revenue per MW	1.4	1.5	1.6	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8					
Revenue (c)	141.1	148.1	155.5	163.3	171.4	360.0	378.0	396.9	416.8	437.6	689.3	723.7	759.9	797.9	837.8					
PV (c)	2,192.8																			
20-Year Forecast																				
PV (a) (years 1-20)	2,357.5																			
PV (b) (years 1-20)	2,236.3																			
Revenue per MW	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
Revenue (c)	110.7	116.2	122.0	128.1	134.5	282.5	296.7	311.5	327.1	343.4	540.9	567.9	596.3	626.2	657.5	920.5	966.5	1,014.8	1,065.5	1,118.8
PV (c)	2,357.5																			

Appendix 2

Table 5: Calculation of Revenue Allowance (INR million)

Year =>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Asset Base																				
Capacity (MW)	100.0	100.0	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	300.0	300.0	300.0	300.0	300.0	400.0	400.0	400.0	400.0	400.0
Opening value	-	510.8	510.8	510.8	510.8	510.8	1,489.8	1,489.8	1,489.8	1,489.8	1,489.8	3,328.6	3,328.6	3,328.6	3,328.6	3,328.6	6,736.5	6,736.5	6,736.5	6,736.5
Transfers	510.8	-	-	-	-	979.1	-	-	-	-	1,838.8	-	-	-	-	3,407.9	-	-	-	-
Closing value	510.8	510.8	510.8	510.8	510.8	1,489.8	1,489.8	1,489.8	1,489.8	1,489.8	3,328.6	3,328.6	3,328.6	3,328.6	3,328.6	6,736.5	6,736.5	6,736.5	6,736.5	6,736.5
Spare Capacity Account																				
Capacity (MW)	300.0	300.0	300.0	300.0	300.0	200.0	200.0	200.0	200.0	200.0	100.0	100.0	100.0	100.0	100.0	-	-	-	-	-
Opening value	2,043.0	1,748.9	1,993.9	2,270.9	2,583.8	2,937.2	2,224.2	2,524.6	2,863.6	3,246.1	3,677.6	2,082.1	2,356.6	2,665.9	3,014.7	3,407.9	-	-	-	-
Transfers	(510.8)	-	-	-	-	(979.1)	-	-	-	-	(1,838.8)	-	-	-	-	(3,407.9)	-	-	-	-
Deferred ARR	216.7	245.0	276.9	312.9	353.4	266.1	300.4	339.0	382.5	431.5	243.3	274.4	309.4	348.8	393.1	-	-	-	-	-
Closing value	1,748.9	1,993.9	2,270.9	2,583.8	2,937.2	2,224.2	2,524.6	2,863.6	3,246.1	3,677.6	2,082.1	2,356.6	2,665.9	3,014.7	3,407.9	-	-	-	-	-
Allowed revenue on Asset Base																				
Return on capital	61.5	59.5	57.4	55.4	53.3	169.2	163.2	157.2	151.2	145.2	360.8	347.4	334.0	320.6	307.2	704.4	677.3	650.2	623.1	596.0
Depreciation (incl. ADD)	17.9	17.9	17.9	17.9	17.9	52.1	52.1	52.1	52.1	52.1	116.5	116.5	116.5	116.5	116.5	235.8	235.8	235.8	235.8	235.8
O&M	7.7	8.0	8.4	8.9	9.3	19.6	20.5	21.6	22.6	23.8	37.4	39.3	41.3	43.3	45.5	63.7	66.9	70.2	73.8	77.4
Interest on working capit	2.3	2.3	2.3	2.3	2.3	6.3	6.3	6.3	6.3	6.3	13.1	13.0	12.9	12.9	12.9	24.7	24.5	24.3	24.2	24.0
Total allowed revenue	89.4	87.7	86.1	84.4	82.8	247.2	242.2	237.2	232.3	227.4	527.8	516.2	504.7	493.3	482.1	1,028.6	1,004.4	980.5	956.8	933.2
Price per MW	0.89	0.88	0.86	0.84	0.83	1.24	1.21	1.19	1.16	1.14	1.76	1.72	1.68	1.64	1.61	2.57	2.51	2.45	2.39	2.33

Transmission Access Pricing for Renewable Energy Generation

The high cost of grid connectivity is a key constraint to promoting renewable energy, yet it is difficult to plan for requisite transmission system expansion when the quantity and timing of generation additions are uncertain. Renewable energy and transmission development are thus interdependent. This study derives from real issues faced in a loan program of the Asian Development Bank in India. Constructing surplus transmission capacity raises important regulatory questions on appropriate pricing mechanisms to pay for it. This is a review-in-progress of various approaches used in countries with similar regulatory environments, so that policy makers may examine approaches that may be relevant to their particular needs.

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