Renewable Electricity and Backup Capacities: An (Un-) Resolvable Problem?

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ABSTRACT

Public support for renewables has led to an unexpected investment momentum in Germany. A consequence is reduced wholesale electricity prices, the so-called merit order effect of renewables. We estimate this reduction using an econometric approach and give a quantitative overview of the financial situation of conventional generators. Our results indicate that investments in new conventional capacities are economically unviable. With the current market design, this situation is going to impact supply security at least in the long run. A popular approach to address this issue is the introduction of additional public support for conventional power plants. However, we believe that subsidizing renewable and conventional capacities contradicts the idea of a liberal market. We present two alternatives: State control of investments in renewables through auctions (as proposed by the European Commission), and a premium paid to representatives of the demand side (such as retailers) dependence of their shares of renewables.

Keywords: Renewables, Backup Capacity, Merit Order, Missing Money, Supply Security, Market Design, Germany

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1. INTRODUCTION

Public support of renewable electricity normally aims at ensuring recovery of total cost plus a given return on investment. For wind and photovoltaics (PV), total cost consists almost exclusively of investment cost. However, in liberalized electricity markets, all power is indiscriminately sold on the same market. Having almost no marginal cost, wind and PV power generation are preferred in the merit order over coal-fired and gas-fired power generation. State aid in favor of renewables therefore implies reduced operation hours of conventional generators, particularly for combined cycle gas turbines (CCGT). Under current European market conditions, they have higher marginal cost than coal-fired power generators. The squeezing out of gas-fired power generation by renewables reduces wholesale power prices which in turn has a negative impact on the profitability of conventional power plants. This effect is called the merit order effect of renewables. There are several studies that have quantified the merit order effect of renewables. Our study also presents estimates for the merit order effect to give a quantitative overview of the financial situation of power producers but it differs from most other studies in that we do not use a complex fundamental model of the electricity market but a simpler econometric approach.

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However, our main goal is not a mere quantification of the merit order effect but rather its implication on the current contribution margins of the remaining power generators that do not benefit from governmental support. In market economies, declining prices usually lead to declining supply. But in the case of renewables, support schemes prevent standard market reactions. In the end, potential investors might even call for public support to build conventional generation capacities to provide security of supply, especially in times of little wind and sun (backup capacities). If governments were to accept such claims, both types of capacities (renewable and conventional) would end up being subsidized. In our opinion, this is obviously a contradiction to the idea of liberal electricity markets. We present two alternative concepts that may solve the described dilemma. The first concept is the state control of renewable generation investments through auctions as proposed in the guidelines of the European Commission on renewable energy state aid (Brussels 2014/C 200/01). The second concept is a modified support scheme to representatives of the demand side in favor of renewables which accounts for overcapacities in the market for electricity generation.

In the next section 2, we give a short overview of the market for electricity and the support scheme for renewables in Germany. In section 3, we estimate the merit order effect of renewables to facilitate the understanding of the current financial situation of conventional power producers. We present and discuss the first alternative market concept consisting of renewable capacity auctions in section 4 while we present and discuss our second market concept consisting of premiums for renewable power generation to representatives of the demand side in sections 5 and 6 before concluding this manuscript in section 7.

2. BACKGROUND

State aid in favor of renewable electricity generation has led to an unexpected investment momentum in many countries. In the case of Germany, the generation share of renewables increased from 5 percent to about one third within a time frame of only 15 years. In 1990/1991, feed-in fees for renewable electricity generation were introduced (Electricity Feed-In Act 1990) to stimulate innovation and technical progress. In 2000, the support scheme was extended in order to incentivize the market integration of renewable power generation against the resistance and market power of incumbent utilities. For the time being, the explicit aim of the German support scheme is a share of at least 35% renewable generation until 2020. The feed-in fees are set to correspond to the technology-specific full cost of renewable power generation[1] and are legally secured for a period of 20 consecutive years after commissioning.[2] Assuming ongoing technical progress, it was foreseen that feed-in fees decline with the year of installation. For many technologies however, this decline had been reverted by amendments (approximately every third year).

On the one hand, thanks to this generous support in Germany, installed capacities of wind, PV, and biogas combined already exceed the annual peak load which is about 80 Gigawatts. On the other hand, expenditures for the state aid are skyrocketing. In Germany and many other countries, the state aid is not financed via public budgets but by a levy on electricity consumption. The resulting market distortion is indicated in Table 1 which shows the total final user expenditures of

1. In the case of onshore and offshore wind, the payments also depend in a rather complex way on the location of the installation.

2. Furthermore, unproduced electricity which has not been produced due to the intervention of system operators is also awarded with the feed-in payment

Table 1: Electricity expenditures of final consumers in Germany, 2010–2014

	2010	2011	2012	2013	2014*
	[billions of Euros]				
Total annual expenditures	**60.9**	**63.6**	**64.3**	**71.0**	**70.3**
Expenditures induced by the government	**17.2**	**23.0**	**23.3**	**30.0**	**32.3**
• Electricity taxes	6.4	7.2	7.0	7.0	6.6
• Concession fees	2.1	2.2	2.1	2.1	2.0
• Net support for renewable electricity	8.3	13.4	14.0	19.8	22.3
• Net support of combined heat and power	0.4	0.2	0.3	0.4	0.5
• Support for offshore grid (§ 17F EnWG)	-	-	-	0.8	0.8
Expenditures regulated by the government	**16.9**	**17.6**	**19.0**	**21.2**	**21.4**
• Fees for the transmission grid	2.2	2.2	2.6	3.0	3.1
• Fees for the distribution grid	14.7	15.4	16.4	18.2	18.3
Expenditures driven by the market	**26.8**	**23.1**	**22.0**	**19.8**	**16.6**
• Market value of renewable electricity	3.5	4.4	4.8	4.2	4.1
• Generation, marketing and sales*)	23.3	18.6	17.2	15.6	12.6

*) Excluding expenditures for auto-generation; data source: Independent Expert Commission 2015, p. 80

electricity in Germany. In recent years both the support for renewable electricity and the grid fees have passed the total expenditures for electricity generation incl. marketing and sales.

Due to the merit order effect of renewables, wholesale electricity prices have fallen below marginal cost even of highly efficient CCGT. Thus, investments in conventional generation capacities deemed to be necessary in the long run have been cancelled. In addition to this, several modern units have been taken out of operation. However, gas-fired power plants are regarded as being ideal backup units due to their potentials for a flexible operation.

In fact, the withdrawal of investment projects is a typical market reaction to situations with obvious production overcapacities. Investors are waiting until they anticipate an increase in wholesale prices which allows them to achieve expected rates of return. However, this simple market mechanism does not apply for subsidized renewables in Germany. The renewable energy policy legally guarantees cost recovery (more or less) and thus eliminates the economic incentive to adapt investment behavior to market conditions. Accordingly, the market for electricity becomes increasingly distorted.

Following the lack of market signals to control the investments into renewable generation, operators of wind and PV plants have an unusually attractive business environment which obviously cannot be sustainable for the power system in the long run. Governments may eventually proceed to also guaranteeing cost recovery to fossil generators that are deemed necessary to secure electricity supply. However, we believe that more market-oriented alternatives are also suitable to provide supply security. We will present and discuss two of them in the last part of this paper. But first, to improve the understanding of the context of these solutions, we estimate the merit order effect of renewables for 2014.

3. MERIT ORDER EFFECT OF RENEWABLES

In competitive day-ahead markets, hourly prices usually correspond to marginal cost of generation. As already explained, increasing generation from wind and PV leads to decreasing wholesale electricity prices, the so-called merit order effect of renewables. The present section is

Table 2: Merit order effect estimates of wind and PV in Germany, 2006–2012

	2006	2007	2008	2009	2010	2011	2012
	Euros/MWh						
Sensfuß et al. (2008)	-7.8						
Weigt (2009)	-6.2	-10.4	-13.0				
vbw (2011)					-8.0		
Sensfuß (2012)		-5.8	-5.3	-6.0	-5.2	-8.7	-8.9
Speth, Stark (2012)					-5.6	-5.6	
Cludius et al. (2013)			-10.8	-7.8	-6.0	-7.7	-10.1

Data source: Federal Ministry of Economic Affairs and Energy (2014), p. 38.

dedicated to enable a better understanding for the current financial situation of conventional generators by estimating the merit order effect of renewables in 2014.

Several studies have quantified this merit order effect in Germany in the past. An overview of ex-post results for the German day-ahead market is presented in Table 2. Most of them are based on fundamental models (structural models) where supply and demand functions are explicitly modeled, specified, and estimated starting from the economic theory of marginal cost pricing. To estimate the merit order effect of renewables, these models calculate the optimal least-cost power plant dispatch assuming there is no wind and PV feed-in and derive average day-ahead prices. These average prices are compared with average prices resulting from the optimal power plant dispatch if wind and PV feed-in are included.

In contrast to fundamental (structural) models, econometric (reduced form) models are the result of solving the system for endogenous variables expressing them as a function of exogenous variables. Such an approach is used in vbw (2011) and Cludius et al. (2013). In these studies, an econometric approach (reduced form model) is used to quantify wholesale power prices. Again, the model compares two cases, with and without wind and PV. In our manuscript, such an econometric estimation is proposed for a three year period between 2012 and 2014 (1,096 days).

In the literature, fundamental models are usually preferred over econometric models when making market forecasts because of the model's higher degree in detail. However, fundamental models require a much larger data basis (e.g. production capacities and efficiency rates of all generators, failure rates of generators, etc.) and thus, have a higher degree in complexity. In our case, however, the goal is to make a hypothetical backcast of the market instead of a forecast resulting in a lower level of uncertainty. We assume that for such a purpose, choosing a less complex econometric model instead of a more complex fundamental model is appropriate. Our model takes hourly day-ahead prices $p_{h,t}$ (in Euros/MWh) as dependent variables. These data are defined as pooled cross-sectional time series whereby the cross sections represent the 24 hours $\{h, h = 0,...,23\}$ of a day and the time series represent the 1,096 days.[3] The implicit assumption is that the power price of say the 9th hour of the day is dependent on the 9th hour of the previous day (reflected by an autoregressive term) but not on the 8th hour of the same day. This assumption is not quite correct as shown by the correlation matrix of the residuals (see appendix Table A.2). The alternative

3. Due to missing data of independent variables, the coverage is 1053 hours (96%).

specification would be a regular time series model with 24 x 1,096 = 26,304 hourly data points. However, thanks to the robustness of the underlying relationship, such a specification leads to the same results and conclusions as the pool model we propose.

The endogenous variable is explained by a number of independent cross-section specific variables

$PV_{h,t}$	Hourly day-ahead forecasts for photovoltaic generation (MWh)
$WIND_{h,t}$	Hourly day-ahead forecasts for wind generation (MWh)
$P_{coal,t-1}$	Daily spot market coal price (API2 in Euros/t)
$P_{gas,t-1}$	Daily spot market gas price (Euros/MWh)
$P_{co2,t-1}$	Daily spot market price of European emission allowances (Euros/t CO_2)

Forecasts for wind and photovoltaics are taken from the joint data platform[4] of the four German transmission system operators, hourly and daily price data from the European Energy Exchange[5]. Daily data (e.g. fuel and CO_2 prices) are converted into hourly data by assuming that hourly data are equal for all hours of the same day.[6] The implicit assumption is that opportunity cost of fossil power generation is equal for all 24 hours and depends on day-ahead gas, coal, and emission prices. In addition, a number of daily dummy variables have been included. They take price effects into account for days during the daylight saving period *DS*, Saturdays, Sundays, and public holidays. Furthermore, in order to eliminate the effect of electricity price outliers, two variables $SPIKES_{up}$ and $SPIKES_{down}$ are included. These variables are positive on days where the physical price index (Phelix-Base) consisting of the average of the 24 prices is above 55 Euros/MWh (outliers exceeding the 0.95 percentile) or below 17 Euros/MWh (outliers falling below the 0.05 percentile). In both cases this holds for about 55 of the 1,096 days in the estimation period. Both outlier variables are normalized to one so that all price peaks have values between zero and one.

In addition to the twelve cross-sectional specific variables, two variables are included that have a common effect on all hours of the day, a dummy variable for the Christmas season and the endogenous variable delayed by 7 days. Thus, the full model comprises of 12 x 24 + 2 = 290 coefficients to be estimated. The mathematical formulation of the model can be found below, see equation (1).

$$\begin{aligned} p_{h,t} = {} & a_{h,0} + a_{h,1}PV_{h,t} + a_{h,2}WIND_{h,t} + a_{h,3}p_{coal,t-1} + a_{h,4}p_{gas,t-1} + a_{h,5}p_{co2,t-1} \\ & + a_6 DS_t + a_{h,7}SAT_t + a_{h,8}SUN_t + a_9 HOLIDAY_t + a_{h,10}SPIKES_{up,t} \\ & + a_{h,11}SPIKES_{down,t} + a_{12}CHRISTMAS_t + a_{13}p_{h,t-7} \end{aligned} \tag{1}$$

Besides the variables used in our equation, others would surely be relevant also, for example temperatures, heating degree days or cooling degree days. But regarding the size of the country, it is difficult to decide which of the many (daily or hourly) data series should be used. In addition, collinearity problems with PV may arise. But to assess the impact of renewables on the electricity prices, we believe the proposed model to be sufficiently complex.

4. See https://www.netztransparenz.de/

5. See https://www.eex.com/en/market-data/

6. For days without fuel trading, the prices of the day before are used. Thus we assume constant fuel prices during weekends according to the closing price of Fridays.

Table 3: Overall descriptive statistics of the variables used in the model

	Electricity price Euros/MWh	Hourly PV forecast 1,000 MWh	Hourly wind forecast 1,000 MWh	Coal price (API2) Euros/t	Gas price Euros/MWh	CO_2 price Euros/t
Mean	37.72	3.475	5.679	68.81	26.05	5.94
Median	36.44	0.169	4.192	65.61	26.47	6.03
Maximum	210.00	24.496	28.280	92.04	28.25	9.31
Minimum	-221.99	0	0.235	54.67	21.89	2.72
Std. Dev.	16.65	5.338	4.794	9.96	1.30	1.37
Skewness	-1.06	1.59	1.64	0.48	-0.91	0.04
Kurtosis	25.31	4.57	5.81	1.96	3.15	2.18
Jarque-Bera	550,350	13,664	20,209	91.2	153.8	30.3
Observations	26,304	26,115	25,950	1096	1096	1081
Cross-sections	24	24	24			

Hourly / daily data between 2012 and 2014; Data source: EEX, TSOs, own calculations.

Table 3 presents the overall descriptive statistics of variables used in the model (except for dummy and spike variables). The cross-sectional descriptive statistics are shown in the appendix (see appendix Table A.1). According to Table 3, the average wholesale electricity price was 37.72 Euros/MWh varying between -222 and $+210$ Euros/MWh in the period from 2012 to 2014. During that time, the average natural gas price was 26.05 Euros/MWh while the price for CO_2 emission allowances was 5.94 Euros/t. With these figures, the economic challenge of gas-fired electricity generation in Germany becomes quite obvious.[7]

To correct for the observed serial correlation of the residuals, a cross section specific autoregressive estimation AR(1) with a lag of one day is applied. This adds another 24 AR(1)-coefficients to the model. The estimation results of the pooled least squares regression using White's cross-section standard errors and covariance (robust to heteroscedasticity and serial correlation) are highly significant with more than 87 percent of the variance of the dependent variable being explained. The AR(1)-term is 0.4 on average with a maximum of 0.612 for the 17th hour.

The estimation results of the main parameters are shown in Table 4. As expected, all coefficients explaining the price effect of forecasted wind feed-in are negative and highly significant at the 1 percent level. This also applies for forecasted PV feed-ins between 8.00 a.m. and 8.00 p.m.

The given results can be used to simulate hourly electricity wholesale prices for these three cases: with wind and PV feed-in, without PV feed-in, and with neither wind nor PV feed-in. Figure 1 shows the results as an ordered price curve for the year 2014. In this figure, the first hour is the hour with the highest price in 2014, the second hour the one with the second highest price, and so forth. The average simulated day-ahead price for 2014 is 33.70 Euros/MWh. Without PV, the average simulated price would be 38.28 Euros/MWh. According to Figure 1, the PV price effect is unevenly distributed. It is high if the day-ahead price is high and low if the price is low. This corresponds to the fact that PV tends to reduce peak prices and has quite a little effect on off-peak prices during the nights.

7. Assuming a fuel efficiency of 55% and a CO_2 output of 0.3 t per MWh electricity generated, the marginal cost of gas generation would be 26.05/0.55 + 0.3x5.95 = 49.15 Euros/MWh

Table 4: Main results of the Pooled Least Squares Estimation

Hour	AR(1)	PV forecast		Wind forecast		Coal price		Gas price		CO_2 price	
0	0.453	-0.241		-1.378	**	0.256	**	0.108		0.745	**
1	0.468	0.568		-1.480	**	0.202	**	0.145		0.810	**
2	0.400	1.093	*	-1.592	**	0.183	**	0.039		0.897	**
3	0.441	1.040	*	-1.535	**	0.153	**	0.112		0.725	**
4	0.401	0.994		-1.454	**	0.144		0.155		0.653	**
5	0.437	-6.761		-1.254	**	0.166	**	0.303		0.777	**
6	0.266	-5.600	**	-1.251	**	0.123		0.752		0.585	**
7	0.254	-2.647	**	-1.303	**	0.140	**	1.179	**	0.286	
8	0.289	-1.691	**	-1.297	**	0.184	**	1.237	**	0.181	
9	0.369	-1.637	**	-1.422	**	0.167	**	1.287	**	0.450	
10	0.371	-1.574	**	-1.389	**	0.154	**	1.209	**	0.721	**
11	0.351	-1.568	**	-1.363	**	0.134	**	1.234	**	0.707	**
12	0.388	-1.476	**	-1.288	**	0.155	**	0.947	**	0.670	**
13	0.382	-1.397	**	-1.232	**	0.130	**	0.846	**	0.609	**
14	0.349	-1.406	**	-1.152	**	0.095	**	0.812	**	0.637	**
15	0.364	-1.281	**	-1.082	**	0.065		1.021	**	0.718	**
16	0.513	-1.230	**	-1.106	**	0.001		1.298	**	0.820	**
17	0.612	-1.157	**	-1.254	**	-0.043		1.874	**	0.968	**
18	0.402	-1.766	**	-1.518	**	0.064		1.952	**	0.935	**
19	0.451	-3.900	**	-1.438	**	0.075		2.148	**	1.051	**
20	0.431	-7.055	**	-1.191	**	0.111	**	1.888	**	0.885	**
21	0.456	-2.548		-1.117	**	0.192	**	1.369	**	0.701	**
22	0.390	0.104		-1.138	**	0.301	**	0.568	**	0.465	**
23	0.372	1.253	*	-1.285	**	0.286	**	0.183		0.688	**
Mean	0.400	-1.662		-1.313		0.143		0.944		0.695	

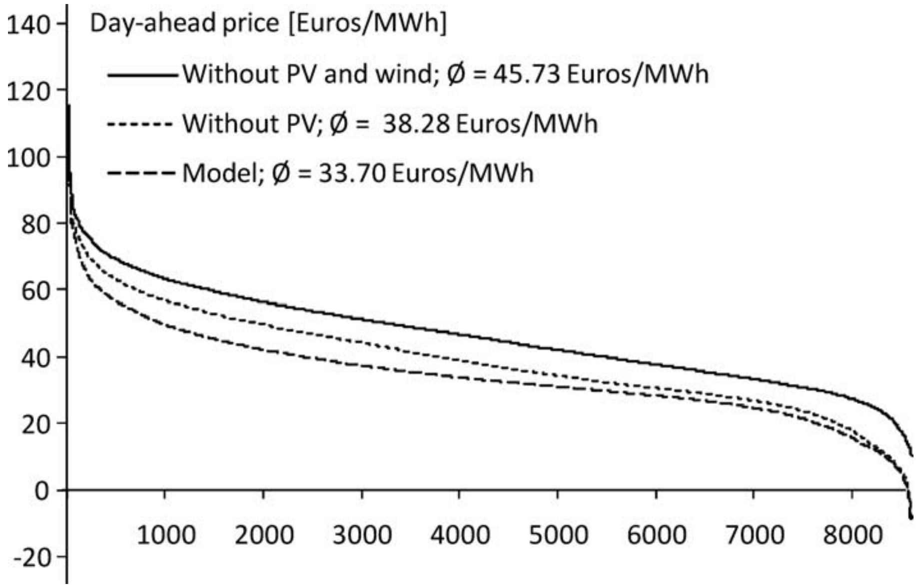
** significant at 1% level; * significant at 5% level. Data source: 1,053 induced observations (days), 25,067 total observations; Source: Own calculations.

Without wind and PV, the average simulated day-ahead price is 45.73 Euros/MWh. In contrast to PV, the price effect of wind is distributed quite evenly over the 8,760 hours of the year which reflects the random nature of wind generation. Taking PV and wind together, the merit order effect of renewables in 2014 can be quantified to about 12 Euros/MWh. Following these results, the average day-ahead price in 2014 would have been 36 percent higher than the one observed if there had not been any electricity feed-in from wind and PV generation in 2014.[8]

As a consequence of the significant (and further growing) merit order effect of renewables, conventional power producers are losing contribution margins and therefore their economic foundation. However, conventional plants are essential for securing electricity supply in times of little wind and sun (at least as long as renewables are not able to guarantee a full market supply). Because energy supply security is one of the foundations for national welfare (see another of our publica-

8. Due to declining wholesale electricity prices and market coupling in northwest Europe, German net electricity exports are growing and have surpassed 8 percent of the national electricity generation in 2014. Thus, growing renewable electricity generation in Germany also implies a merit order effect in the neighboring countries which in turn also challenges the economics of electricity generation there.

Figure 1: Ordered day-ahead prices in Germany 2014



tions), it seems necessary to clarify the roles of renewables and backup capacities in future power systems by either revising the support scheme for renewables or by introducing an additional support mechanism in favor of conventional backup capacities.

A first step along this line is the amendment of the Renewable Electricity Act in 2014. With the amendment, an upper bound for the share of renewables has been introduced in addition to the already existing lower bound. To be more precise, the target for renewable electricity is now set to a range between 40 and 45 percent in 2025.[9] One of the instruments to ensure achievement of this revised target is the introduction of flexible feed-in payments: If wind or PV investments in a certain period exceed a predefined level, new installations receive a reduced premium and vice versa. Such a system had already been introduced successfully for PV when new installations had surpassed 7,000 MW in a year while the government only expected about 2,500 MW. As a consequence, payments for new installations had been reduced and brought new PV installations down to roughly 2,000 MW per year. It is to be expected that flexible wind premiums would generate similar effects.

However, it is questionable whether or not such measures would be sufficient to overcome the market distortions. With the current market design, a renewable share of 40 to 45 percent in 2025 might turn out to be incompatible with a reliable investment environment for backup generation in spite of the expected phase-out of the remaining 11 GW nuclear capacities in Germany until 2022. A policy induced premature decommissioning of further conventional (inflexible) capacities might ease the issue of overcapacities. However, such a strategy would lead to stranded costs which need to be borne either by the owners of the plants, the consumers, or the tax payers. In the following sections, we will present and discuss two alternative solutions to such a revision

9. Another modification is that fixed feed-in payments have been replaced by payments of a so-called “market premium” which covers the difference between the politically estimated generation costs and the monthly average wholesale market price.

of the support scheme for renewables: auctions for renewable generation capacities and a market premium which is oriented towards backup capacities.

4. AUCTIONS FOR CONTROLLING INVESTMENTS INTO RENEWABLE ELECTRICITY GENERATION

There are several advantages if the government bases support for renewable capacities on auctions. In our opinion, the most important one is that the level of state aid is determined by market forces and not by some ministerial bureaucracy or external consultants. We will not discuss the implementation of such auctions in detail (for this, see for example Nielsen et al. 2011, Maurer and Barroso 2011, Fraunhofer and Ecofys 2014). However, we want to stress out that the final advantage depends on the design of the auctions. In order to have an auction outcome that is unaffected by market power, a larger number of potential investors needs to participate. Even though this is easily said, it might prove to be difficult to put into practice because companies would need to be pre-qualified regarding their qualities in engineering and management to participate in the auctions. Additionally, to prevent strategic behavior of bidders, market participants should also be required to provide some financial guarantee in case investment projects will not be realized in due time. Furthermore, for obvious reasons, contract bidders should be required to already have signed contracts with landowners prior to the auction. Altogether, this restricts the number of possible bidders. As not all bidders can usually be successful in the auctions, some potential investors may need to write-off planning costs. The bidding price will normally also account for the associated financial risks. With this, the required state aid per unit of renewable electricity generation may even exceed the one given in the present support scheme.

These points are well understood by the regulators and solutions have been developed that seem to work in practice. However, a crucial issue remains: As long as renewable capacities are not competitive and cannot be financed by wholesale electricity prices alone, capacity auctions allow direct control of government or state regulators over investments. Auctions should always select the lowest bidders but, eventually, the cost of renewable electricity generation depends on technology, geographic location, and plant size.[10] Should such auctions also incentivize a certain variety of technologies and geographies, their conditions need to be specified with respect to these dimensions. However, as long as the government or a state regulator defines these conditions, auctions become an obvious instrument of centralized investment planning. When defining auction volumes, governments may still respect politically defined renewable targets. But they may also be tempted to reduce auction volumes in order to prevent further increases in retail prices, avoid bottlenecks in transmission and distribution grids, or prevent generation overcapacities and stranded cost of conventional generation and hydropower capacities.

But once state auctions for renewable electricity capacities are in place, the same instrument may also be applied to keep conventional generation capacities from leaving the market or to incentivize new generation or storage capacities that are regarded to be necessary in order to secure the electricity supply in times without wind and sun.[11] In particular, representatives from the utility industry regard such auctions for conventional backup capacities as necessary because the current energy-only markets with their short-term marginal generation cost regime are unable to provide sufficient income to justify investments.[12]

10. This is especially important if a limited power grid is only able to accommodate additional generation capacities in certain locations.

11. A likely parameter for defining eligible technologies is a cap on specific greenhouse gas emissions.

12. Given the currently rather low electricity wholesale prices due to overcapacities, it is obvious that a free market auction would hardly be able to satisfy this expectation in the near future.

Eventually, national governments are bound to virtually receive total control over all generation capacities by organizing auctions for renewable capacities, conventional backup capacities, and possibly also storage capacities. With this, all awarded bidders will receive payments on top of the wholesale power prices once their investment projects are accomplished and are starting to operate. The payments may be refinanced through state budgets or through surcharges on electricity bills. In the end, both will lead to state aid according to the definition of the European Commission: "State aid is defined as an advantage in any form whatsoever conferred on a selective basis to undertakings by national public authorities".[13] In such an environment, hardly any plant operator will be able to financially survive over time unless receiving state aid through successful participation at the auctions.

The original promise of the electricity market liberalization in the European Union was that the market should be able to select its own cost-efficient generation portfolio in order to gain a more efficient electricity supply. However, in the context of state auctions, this promise will no longer hold. The effect of these auctions is that the generation portfolio will be defined by state authorities and that electricity prices will no longer depend on free negotiations and trades among market participants but rather on deals between potential investors and governmental authorities. It is quite astonishing that state-defined auctions for renewable or conventional capacities are often regarded as market-based instruments. Even though the instrument of state auctions is a valid option to manage the electricity market, we are pleading for a categorization as an instrument of planned economies, given the fact that the electricity generation market will be under control of state bureaucracies or powerful interest groups. However, from the free market perspective, this seems to be a rather high price to pay for the management of overcapacities.

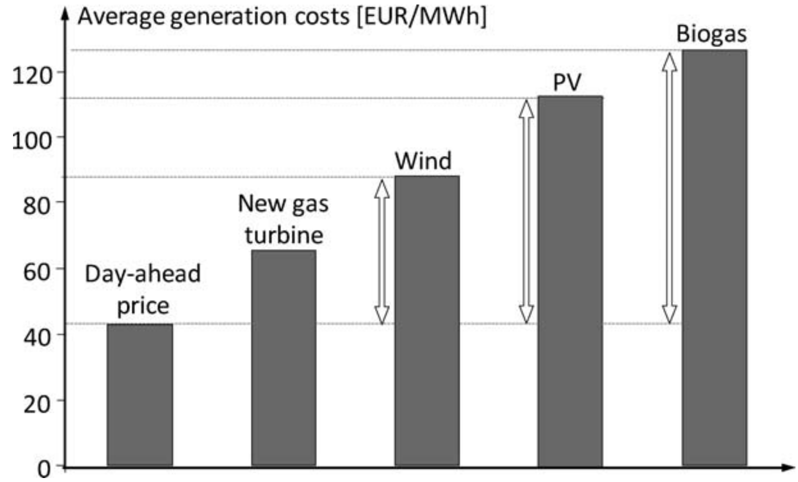
Many governments have implemented other concepts in order to deal with the issue of overcapacities, but the interventions seem to be somehow arbitrary. An example is the recent amendment of the German Renewable Energy Sources Act 2014. With this act, the renewable support will be temporarily suspended if hourly day-ahead wholesale prices are negative during six consecutive hours. The aim of this rule is obvious: Renewable generators should reduce their electricity production in periods of extreme oversupply. For technical and institutional reasons[14], the flexibility of most thermal power stations is limited so that they may still produce at negative wholesale prices. In comparison, the downward flexibility of wind and PV systems is large so that they should be the ones to react on price signals. But one may question the six-hour period of negative wholesale prices. It appears quite easy for larger aggregators of electricity to influence the wholesale power prices in such a way those six consecutive hours with negative prices will or will never occur.

Other governments have applied more drastic interventions at the expense of renewable electricity generation to overcome the issue of generation overcapacities. In extreme cases, support schemes were fully withdrawn with retroactive effect. Obviously, these and similar government interventions avoid excess generation capacities. However, we believe that unsystematic and unforeseeable political decisions are a hindrance to any stable development of the renewable energy industry. For these reasons, we propose a different approach in the following sections.

13. The consequence is that the designs and the outcomes of all auctions are to be controlled by the European Commission so that national governments will not have the last word.

14. Examples are must-run power stations with system service responsibility as well as combined heat and power stations which are operated according to the heat demand.

Figure 2: Contract for differences as support scheme for renewables (current situation)



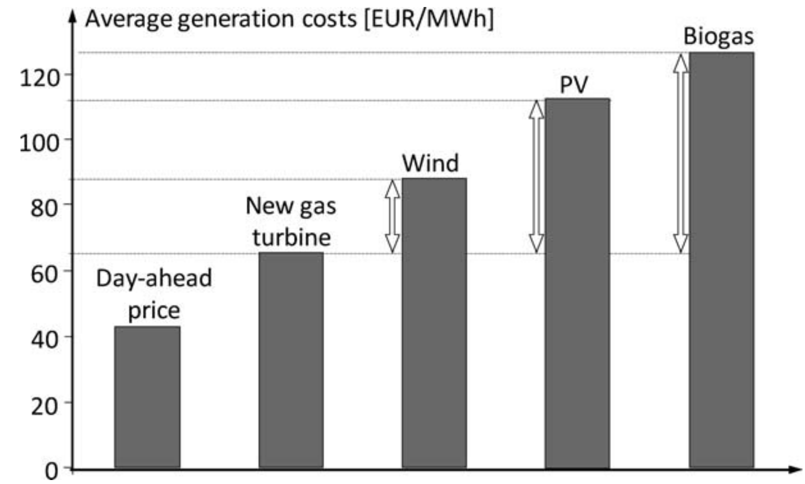
5. MARKET PREMIUMS TO CONTROL INVESTMENTS INTO RENEWABLE ELECTRICITY GENERATION

Usually, economists assume that the optimal way to deal with excess generation capacities would be to let market forces to do their job while governments should only intervene to prevent the abuse of market power and to internalize negative externalities. The following two figures illustrate how this basic idea can be applied to feed-in premiums paid to renewable electricity generators.

Figure 2 shows the basic support scheme which is known under the term “contract for differences” and is presently implemented in several countries. Sometimes, the level of the average day-ahead price is insufficient to cover total cost of electricity generation. Currently, this holds true for both gas turbines and renewables in Germany. However, renewable generators receive premiums that cover the difference between (individual) generation cost and average day-ahead price. Accordingly, the premium leads to cost recovery even if produced renewable electricity is sold at low market prices. But as long as there is no state support for investments in gas turbines or other backup technologies, investments in these technologies remain uneconomical. If backup investments are assumed to be necessary, one solution might lie in some sort of state aid (see section 3) that covers the difference between total average cost and realized day-ahead price. This support would bring backup capacities in a similar economic situation as generation technologies from renewable sources. However, this leads to the downsides that we discussed in section 3.

Figure 3 illustrates an alternative approach to this double subsidization. In the alternative approach, the market premium in favor of renewables is reduced. Here, it is not average day-ahead prices that serve as a benchmark but rather average prices necessary to allow total cost recovery of investments in the most cost-efficient backup technology. As we can see, the day-ahead price shown in Figure 3 fails to justify any investments in generation capacities (renewable and non-renewable). Actually, these situations arise if there are overcapacities present in the system. However, due to a lack of incentives to invest in new plants, overcapacities are going to decrease over time and day-ahead prices are going to start increasing again. At some point, both, backup and renewable in-

Figure 3: Reduction of market premiums to the level of backup cost (alternative approach)



vestments are going to be economically viable again and the paradox of incentivizing investments in new (renewable) production capacities in a situation where the market suffers from overcapacities will be solved.

However, this alternative approach is also associated with several issues. One of these issues is the determination of average day-ahead prices necessary to cover total cost of the most cost-efficient backup capacity. Using the following steps, we quantify the average day-ahead price needed for cost recovery.

- First, a preselection of potential backup generation technologies is required. Eventually, the backup technology which covers an expected capacity shortage in future periods in the most cost-efficient way should determine the answer.
- Second, an assessment of expected annual full-load hours for, let us assume, the next five to ten years is necessary. The full-load hours depend on the load and the available controllable generation capacities that remain after the decommissioning of old plants at the end of their economic lifetime.
- Third, the total cost of each technology has to be quantified. Because of the variable cost such as for fuel and emission allowances, the result also depends on the full-load hours.

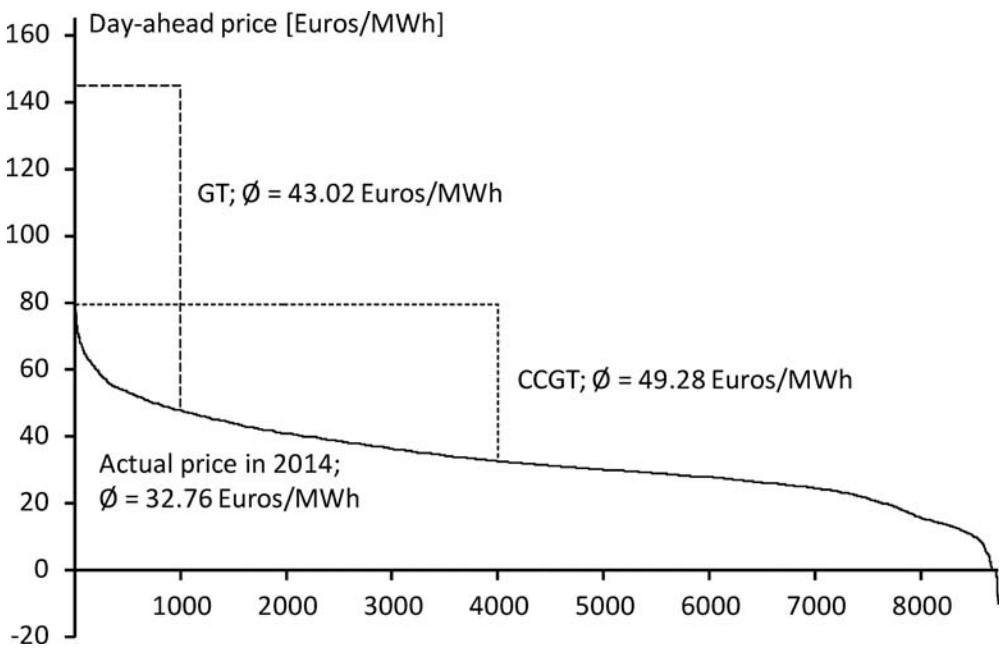
For any backup technology to be economically viable, total annual generation cost need to be covered by revenues. Therefore, expected day-ahead prices must remain above average generation cost for at least the annual full-load hours. Figure 4 illustrates this with the example of two backup technologies operating with natural gas: open cycle gas turbines (GT) and CCGT. The sample data used in these examples are shown in Table 5.

Figure 4 shows price duration curves based on prices in 2014. The figure explains which average day-ahead price would have been needed to cover the total cost of the most cost-efficient backup capacity. If an assumed future generation capacity shortage that needs to be covered by a backup capacity investment has a profile of only 1,000 hours per year, the open cycle GT is the most cost-efficient technology available. In the given case, the open cycle GT requires a day-ahead price of at least 145.02 Euros/MWh for these 1,000 hours (compared to 169.00 Euros/MWh for a

Table 5: Sample data for gas-fired backup generation technologies

		Gas Turbine (GT)	Combined Cycle Gas Turbine (CCGT)
Capital expenditures	Euros/kW	450	950
Utilization period	Years	20	30
Fuel efficiency	%	37	58
Operating costs	% of Invest/a	4	3
Interest rate	%	8	
Profit margin	% of revenue	6	
Natural gas price	Euros/MWh	25.00	
Emission factor	t CO_2/GJ_{therm}	0.056	
	t CO_2/MWh_{therm}	0.20	
Price of CO_2 allowances	Euros/t CO_2	10.00	
Levelized cost of capital	Euros/kW/a	45.83	84.39
Operation and maintenance	Euros/kW/a	18.00	28.50
Fuel costs	Euros/MWh_{el}	67.57	43.10
CO_2 costs	Euros/MWh_{el}	5.41	3.45

Figure 4: Ordered day-ahead prices in Germany allowing for backup investments



CCGT). If we expect the remaining part of the price duration to be unaffected by the backup investment,[15] the necessary day-ahead price must be at least 43.02 Euros/MWh on average to render the investment viable (compared to 45.76 Euros/MWh for CCGT with 1,000 hours per year).

15. This is a simplified assumption that might be modified in a more refined version of the approach.

Assuming that a future capacity shortage has a higher profile of 4,000 hours, choosing CCGT over the open cycle GT would be the better economic alternative. In this case, a day-ahead price of at least 79.26 Euros/MWh is required during these 4,000 full-load hours (compared to 94.27 Euros/ MWh for an open cycle GT). If the remaining day-ahead prices stay unchanged outside of these 4,000 hours, the CCGT investment would become viable at an average day-ahead price of at least 49.28 Euros/MWh.

Comparing these results with the average day-ahead price in 2014 of 32.76 Euros/MWh, it becomes obvious that investments in neither CCGT nor open cycle GT are currently economically viable. If we take into account the merit order effect of renewables for 2014 (about 12 Euros/MWh, see section 3), we can assume that investments in open cycle GT would be economically viable without wind and PV feed-in. As for CCGT investments, an increase of the average day-ahead price by another 4.50 Euros/MWh would be necessary.

The solution discussed so far would induce a reduction of the market premium for investments into renewable generation by roughly 12 to 20 Euros/MWh. Eventually, such a reduction disincentivizes investments into renewable generation capacities and, thus, alleviates the present situation of generation overcapacities. This seems particularly important for offshore wind capacities with high capacity factors of about 50 percent. If such a reform were to be passed, the expected day-ahead prices would increase over time and investments into both, renewable and backup generation technologies, would be economical again at some point.

However, there is an important shortcoming with this approach: The share of renewable power generation may not grow according to the politically defined targets. One conclusion would be that the target of certain shares of renewables is incompatible with the vintage structure of present generation capacities. Following this conclusion, ordered market conditions can only be reestablished with a slower pace of renewable energy investments or a politically forced phase-out of conventional generation capacities. While the first option is politically unpopular, the second option causes high stranded costs and may perhaps be prohibited by legal courts that regard this as a restriction on the freedom of trade.

A deeper analysis leads to the following assessment of the problem: The proposed reduction of market premiums for generation from renewable sources creates a situation in which both, conventional and renewable generation technologies, are equivalent in the economic sense. With this, a reduced premium would be neutral with respect to competition between different technologies. However, the political intention is to have a biased competition in favor of renewables. But instead of a political intervention on the supply side of the market, the regulator may also intervene on the demand side in favor of renewables.

6. THE CRUCIAL ROLE OF THE ELECTRICITY DEMAND

In order to shift market preferences towards renewable capacities, we propose giving incentives to representatives of the demand side instead of offering incentives to producers of renewable energy. Representatives of the demand side might be large industrial customers, electricity retailers, and other so-called balancing responsible parties. Of course, the government could also subsidize renewable energy technologies from the supply instead of the demand side. However, by applying pull mechanisms aimed at the demand side, governments give market forces the opportunity to find innovative and flexible solutions that are likely be precisely tailored to accommodate larger shares of renewables in the electricity market. We believe that the prospects of gaining competitive advantages would be a sufficient stimulus for companies to work out solutions to successfully integrate an increasing share of intermittent supply.

One possible approach would be to impose a certain renewable portfolio standard on balancing responsible parties which requires them to purchase a predetermined and over the time further increasing share of electricity from preregistered renewable generators. However, such a measure would obviously be another rather strong regulative intervention. Again, there is an alternative to such a regulated imposition. Instead of imposing shares of renewables, we propose a monthly premium that is paid to balancing responsible parties according to their monthly share of fluctuating renewables in their power sales portfolio. The proposed premium should be offered in Euros per kWh electricity sold, and be equal to zero if shares of renewables in the sales portfolios remain below a certain minimum threshold. On the other hand, the premium should increase in proportion to the shares of renewables. The effect of such a premium would be a motivation of electricity retailers to prefer electricity from renewables instead of from conventional technologies.

A point of criticism to this suggestion could be that renewable shares in electricity sales portfolios are physically limited by the ability to reliably secure supply. However, this physical limit is variable and can be increased with the implementation of electricity storages, power-to-heat devices, flexible and interruptible loads, and other demand-sided instruments. Therefore, in addition to just incentivizing the demand for renewables themselves, the premium would also serve as a tool to support these kinds of innovations that allow the integration of higher shares of renewables in a reliable power system. If a rather unsatisfying development of renewable generation is observed, the government could raise the premium to stimulate further increases.

Taking it one step further, it seems reasonable to embed such a concept into a European framework. In the beginning, support payments to retailers could be defined by a national government and financed by its consumers. However, once the support scheme satisfies European standards regarding state aid, European retailers purchasing electricity from undertakings listed in a European database of admitted renewable generators would then be eligible to receive the proposed market integration premium. Ideally, this premium would be financed by consumers in the country where the electricity is consumed.

7. CONCLUSION

We have shown that the current support of renewable power generation has a strong impact on wholesale electricity prices (merit order effect of renewables). We presented a pooled cross-sectional time-series model to quantify the merit order effect for 2014. The results indicate that renewable power generation led to an average discount in wholesale prices of approximately 12 Euros/MWh (about 36 percent of the observed baseload price). A consequence of a merit order effect in such an order of magnitude is contribution margins which are insufficient to justify investment in conventional (backup) generation capacities. With the current market design and further increases in shares of renewables, this might even impact supply security (at least in the long run).

In this manuscript, two different concepts are presented to solve this issue. The first concept is an auctioning mechanism for renewables (supply-sided mechanism) granting the regulator control over investments in renewable generation capacities as proposed in the guidelines of the European Commission on renewable energy state aid (Brussels 28.6.2014; 2014/C 200/01). However, we believe that such a measure on the supply side would be a rather strong regulative intervention of the government.

The second concept is a monthly premium paid to power retailers and other representatives of the demand side depending on the share of fluctuating renewables provided in their sales portfolio (demand-sided mechanism). In our opinion, such a demand-sided approach is much more flexible and is even capable of supporting solutions to integrate larger shares of renewables into the power markets (such as backup generation capacities, electricity storage systems, or demand side management). By allowing the market itself to find an optimal solution for the integration of renewables, the idea of liberal markets in the electricity sector would be valued.

However, even if our concept were to be accepted, a transition from the present support system to such a new system would still be a great administrative challenge because a multitude of different stakeholder and interests would be involved. But our proposal has an even more important shortcoming. On the one hand, the supply side (renewable and conventional generators) is heavily lobbying for support payments, capacity premiums, and other state aids and these claims would be at risk. On the other hand, retailers and balancing group managers from the demand side currently do not request any support even though it might be reasonable. Eventually, a reform of renewable electricity support along these lines might just turn out to be politically inopportune.

A. APPENDIX

Table A.1: Descriptive statistics of key variables for the merit order estimation

	Electricity price [Euros/MWh]				PV forecast [1,000 MW]				Wind forecast [1,000 MW]			
Hour	Mean	SD	Min	Max	Mean	SD	Min	Max	Mean	SD	Min	Max
0	29.8	11.0	-149.9	55.1	0.0	0.1	0.0	2.5	5.7	4.6	0.4	26.2
1	27.0	13.2	-200.0	51.8	0.0	0.1	0.0	2.4	5.6	4.6	0.3	26.6
2	25.0	14.2	-222.0	47.0	0.0	0.1	0.0	2.3	5.6	4.6	0.3	26.9
3	23.5	14.7	-221.9	45.2	0.0	0.1	0.0	2.1	5.6	4.6	0.3	27.3
4	24.0	13.6	-199.9	46.2	0.0	0.1	0.0	1.9	5.5	4.6	0.3	27.5
5	26.6	13.3	-199.0	49.6	0.0	0.1	0.0	1.9	5.5	4.6	0.3	27.7
6	33.9	16.8	-199.9	70.9	0.3	0.5	0.0	2.2	5.5	4.6	0.4	27.8
7	42.8	18.9	-156.9	183.5	1.3	1.4	0.0	5.2	5.5	4.7	0.4	27.9
8	46.0	17.9	-1.0	175.6	3.2	2.7	0.0	10.0	5.5	4.8	0.4	28.0
9	45.2	16.0	-2.8	128.1	5.9	3.9	0.1	15.2	5.5	4.9	0.4	28.1
10	43.5	15.2	-5.7	133.9	8.4	4.9	0.4	19.8	5.5	5.0	0.3	28.2
11	43.2	15.0	-8.3	130.3	10.3	5.6	0.5	23.0	5.7	5.1	0.3	28.2
12	40.4	14.3	-29.1	113.0	11.1	6.0	0.5	24.5	5.8	5.2	0.3	28.3
13	38.2	15.1	-59.5	108.9	11.0	6.2	0.5	24.5	5.9	5.2	0.3	28.3
14	36.7	15.6	-100.0	103.7	10.1	6.2	0.3	23.3	5.9	5.1	0.3	28.2
15	37.1	15.1	-100.0	105.5	8.3	5.9	0.1	21.4	5.9	5.0	0.2	28.1
16	38.5	14.3	-46.9	121.1	6.2	5.1	0.0	18.0	5.9	4.9	0.3	27.9
17	44.7	16.5	0.1	151.9	4.0	3.9	0.0	13.5	5.9	4.9	0.4	27.7
18	50.2	18.0	11.0	210.0	2.2	2.5	0.0	8.4	5.8	4.8	0.4	27.4
19	50.7	15.3	9.3	169.9	0.9	1.2	0.0	4.8	5.7	4.7	0.5	27.2
20	45.7	11.7	9.3	136.0	0.2	0.3	0.0	2.4	5.7	4.7	0.4	26.9
21	41.2	10.0	8.8	94.9	0.0	0.1	0.0	2.2	5.7	4.7	0.5	26.6
22	39.3	9.0	7.1	79.7	0.0	0.1	0.0	2.2	5.7	4.6	0.5	26.3
23	32.7	9.5	-91.0	57.9	0.0	0.1	0.0	2.3	5.7	4.6	0.5	26.0

Table A.2: Correlation matrix of the cross section residuals

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
0	1	0.78	0.61	0.48	0.46	0.54	0.27	0.26	0.27	0.29	0.27	0.22	0.20	0.18	0.13	0.17	0.19	0.15	0.13	0.08	0.16	0.20	0.29	0.27
1	0.78	1	0.80	0.65	0.61	0.67	0.35	0.32	0.30	0.29	0.24	0.19	0.16	0.13	0.11	0.12	0.15	0.14	0.12	0.06	0.12	0.17	0.23	0.24
2	0.61	0.80	1	0.79	0.76	0.67	0.39	0.30	0.28	0.25	0.21	0.18	0.14	0.11	0.09	0.09	0.13	0.12	0.11	0.05	0.09	0.16	0.20	0.22
3	0.48	0.65	0.79	1	0.87	0.72	0.38	0.32	0.29	0.24	0.22	0.21	0.17	0.07	0.04	0.05	0.11	0.13	0.09	0.07	0.10	0.17	0.18	0.20
4	0.46	0.61	0.76	0.87	1	0.78	0.39	0.33	0.30	0.27	0.24	0.22	0.18	0.11	0.08	0.10	0.15	0.14	0.11	0.09	0.11	0.18	0.20	0.24
5	0.54	0.67	0.67	0.72	0.78	1	0.58	0.47	0.40	0.35	0.29	0.24	0.21	0.16	0.13	0.15	0.22	0.20	0.15	0.12	0.17	0.24	0.24	0.27
6	0.27	0.35	0.39	0.38	0.39	0.58	1	0.63	0.48	0.44	0.33	0.25	0.25	0.23	0.17	0.20	0.26	0.23	0.22	0.20	0.27	0.29	0.23	0.20
7	0.26	0.32	0.30	0.32	0.33	0.47	0.63	1	0.80	0.59	0.42	0.31	0.31	0.28	0.21	0.22	0.26	0.29	0.28	0.18	0.25	0.25	0.21	0.17
8	0.27	0.30	0.28	0.29	0.30	0.40	0.48	0.80	1	0.78	0.58	0.45	0.39	0.34	0.29	0.29	0.32	0.33	0.27	0.22	0.27	0.26	0.20	0.17
9	0.29	0.29	0.25	0.24	0.27	0.35	0.44	0.59	0.78	1	0.85	0.70	0.61	0.55	0.45	0.41	0.43	0.37	0.30	0.23	0.34	0.32	0.31	0.24
10	0.27	0.24	0.21	0.22	0.24	0.29	0.33	0.42	0.58	0.85	1	0.86	0.76	0.66	0.53	0.47	0.46	0.36	0.31	0.24	0.34	0.31	0.33	0.27
11	0.22	0.19	0.18	0.21	0.22	0.24	0.25	0.31	0.45	0.70	0.86	1	0.87	0.71	0.56	0.49	0.48	0.38	0.30	0.22	0.32	0.29	0.32	0.26
12	0.20	0.16	0.14	0.17	0.18	0.21	0.25	0.31	0.39	0.61	0.76	0.87	1	0.86	0.66	0.57	0.52	0.39	0.30	0.21	0.30	0.29	0.32	0.26
13	0.18	0.13	0.11	0.07	0.11	0.16	0.23	0.28	0.34	0.55	0.66	0.71	0.86	1	0.85	0.78	0.67	0.43	0.31	0.23	0.32	0.30	0.29	0.24
14	0.13	0.11	0.09	0.04	0.08	0.13	0.17	0.21	0.29	0.45	0.53	0.56	0.66	0.85	1	0.91	0.74	0.43	0.31	0.23	0.29	0.27	0.24	0.18
15	0.17	0.12	0.09	0.05	0.10	0.15	0.20	0.22	0.29	0.41	0.47	0.49	0.57	0.78	0.91	1	0.84	0.51	0.38	0.28	0.33	0.31	0.28	0.21
16	0.19	0.15	0.13	0.11	0.15	0.22	0.26	0.26	0.32	0.43	0.46	0.48	0.52	0.67	0.74	0.84	1	0.71	0.43	0.31	0.41	0.39	0.35	0.25
17	0.15	0.14	0.12	0.13	0.14	0.20	0.23	0.29	0.33	0.37	0.36	0.38	0.39	0.43	0.43	0.51	0.71	1	0.65	0.36	0.44	0.43	0.36	0.21
18	0.13	0.12	0.11	0.09	0.11	0.15	0.22	0.28	0.27	0.30	0.31	0.30	0.30	0.31	0.31	0.38	0.43	0.65	1	0.60	0.51	0.45	0.34	0.20
19	0.08	0.06	0.05	0.07	0.09	0.12	0.20	0.18	0.22	0.23	0.24	0.22	0.21	0.23	0.23	0.28	0.31	0.36	0.60	1	0.66	0.49	0.36	0.18
20	0.16	0.12	0.09	0.10	0.11	0.17	0.27	0.25	0.27	0.34	0.34	0.32	0.30	0.32	0.29	0.33	0.41	0.44	0.51	0.66	1	0.73	0.50	0.28
21	0.20	0.17	0.16	0.17	0.18	0.24	0.29	0.25	0.26	0.32	0.31	0.29	0.29	0.30	0.27	0.31	0.39	0.43	0.45	0.49	0.73	1	0.71	0.39
22	0.29	0.23	0.20	0.18	0.20	0.24	0.23	0.21	0.20	0.31	0.33	0.32	0.32	0.29	0.24	0.28	0.35	0.36	0.34	0.36	0.50	0.71	1	0.62
23	0.27	0.24	0.22	0.20	0.24	0.27	0.20	0.17	0.17	0.24	0.27	0.26	0.26	0.24	0.18	0.21	0.25	0.21	0.20	0.18	0.28	0.39	0.62	1

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