RAISELIFE
Raising the Lifetime of Functional Materials for Concentrated Solar Power Technology

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Catalogue of good practices, public version

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Executive Summary

The main objectives of the Raiselife project-Work Package 6 (WP6) are the dissemination and exploitation of the investigations carried out in the whole project to the EU community, to assist market penetration of the developed technology, to provide the necessary competences of technicians and professionals on coatings and lifetime prediction, to develop and disseminate a catalogue of good practices for the use of functional materials in CSP, including the RAISELIFE materials developments and to contribute to the development of guidelines for the standardization of CSP components.

In order to achieve these goals, this report “Catalogue of good practices, public version” presents the main results of the previous WPs and includes a compilation of good practices on: (a) the detection and monitoring of degradation during service and operation in the field as well as after accelerated testing, derived from agreements reached between all testing institutions/partners, (b) application, operation and maintenance of functional materials and coatings, e.g. information on cleaning, collected and derived from recommendations of coating and operating partners, (c) economic impacts and economic viability of different measures influencing the in-service degradation, (d) testing protocols and accelerated aging procedures to reproduce outdoor effects, derived from the knowledge and results of the partners performing accelerated aging tests, (e) good practices and a protocol for evaluating corrosion in molten salt environments will be developed in the frame of WP4, (f) good practice on steel selection for CSP.
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5. Best practices accelerated aging of secondary reflectors in the solar field (BSII, SOL, Fraunhofer, CIEMAT, DLR)

6. Best practices on accelerated aging of receivers for solar towers (DLR, CIEMAT, BSII, Fraunhofer, DFI, INTA, PROMES)

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Chapter 1: D6.4 Best Practice on in-Service Degradation Monitoring

1. Scope and objective

This project focuses on raising the lifetime of five key functional materials for concentrated solar power (CSP) technologies: 1) protective and anti-soiling coatings for primary reflectors, 2) very high-reflective surfaces for heliostats, 3) high-temperature secondary reflectors, 4) receiver coatings, 5) corrosion resistant high temperature metals and coatings for molten salts. For this purpose, the project brings together a broad consortium formed of leading industry partners, SMEs and research institutes of the concentrated solar thermal and material science sector. The project scope has been significantly shaped by the leading Engineering, Procurement and Construction (EPC) of ST technology BSII. This unique constellation permits a direct transfer of the obtained results in RAISELIFE into new commercial CSP plants within less than 5 years.

The gained experience on accelerated testing methodologies, degradation monitoring and measurement techniques as well as sample treatment and correlation to in-service results will be summarized in a catalogue of good practices. This catalogue of good practices will be developed by the partners to reduce in-service degradation and will be made available to the CSP community by transferring it to national and international standardization committees and feeding the results into working groups like SolarPaces Task III.

This catalogue will make use of the results of WP 1 to 5 and will include a compilation of good practices on: (a) the detection and monitoring of degradation during service and operation in the field as well as after accelerated testing, derived from agreements reached between all testing institutions/partners, (b) application, operation and maintenance of functional materials and coatings, e.g. information on cleaning, collected and derived from recommendations of coating and operating partners, (c) economic impacts and economic viability of different measures influencing the in-service degradation, which will make use of both practical experiences of industrial partners and results from the economic assessments of T5.3, (d) testing protocols and accelerated aging procedures to reproduce outdoor effects, derived from the knowledge and results of the partners performing accelerated aging tests, (e) good practices and a protocol for evaluating corrosion in molten salt environments will be developed in the frame of WP4, (f) good practice on steel selection for CSP.

In particular, this deliverable is devoted to the best practice on in-service degradation monitoring, gathering the most relevant information for standardizing the procedures of the degradation of CSP components in order to have a better understanding of the degradation processes that take place in a plant.
2. **Normative references**

- AEN/CTN 206, Draft receiver test methods.
- ISO 17245: Corrosion of metals and alloys - Test method for high temperature corrosion testing of metallic materials by immersing in molten salt or other liquids under static conditions ISO 17245 (2015) ISO TC156 WG 13 (High Temperature Corrosion).
3. Terms and definitions

**Reflectance, ρ**

Light interacts with the matter it intercepts. The light can be absorbed, transmitted, or reflected according to the three corresponding ratios, depending on the wavelength of the light and the material properties. The material properties associated with these behaviors are absorptance, $\alpha$, transmittance, $\tau$, and reflectance, $\rho$. Usually a combination of these processes takes place and they are subjected to the law of conservation of energy, which states that $\alpha + \tau + \rho = 1$. The transmittance is considered to be zero for opaque objects. Reflectance is defined as the ratio of the radiant flux reflected from a surface to that of the incident flux.

Reflectance is dependent on the wavelength, $\lambda$, the angle of incidence, $\theta_i$, between the incoming light and the normal to the mirror surface, and light polarization. The amount of reflected radiance is a material property and its angular distribution is a property of the microscopic surface flatness. Therefore, reflectance is distinguished into diffuse or specular reflectance as described below. Polarization can be neglected only at near normal incidence, i.e. $\theta_i < 15^\circ$. Because sunlight is not polarised, for CSP applications one has to consider the unpolarized reflectance, given by the average value of s and p polarized reflectances. In the following, polarization will be omitted, and with “reflectance” it is referred to “unpolarized reflectance”. The reflectance at oblique incidence angles must be considered for s and p polarization separately and then the results averaged. [1]

**Hemispherical reflectance**

The spectral hemispherical reflectance, $\rho_{h,\lambda}(\lambda, \theta_i, h)$, describes the total amount of specular and diffuse radiation reflected into the hemisphere above the reflective surface of a material. It is a function of the wavelength, $\lambda$, and the incident angle, $\theta_i$, of the incident light. It integrates the reflected intensity over the entire hemisphere of possible reflection. [1]

**Diffuse reflectance**

If a parallel, extended bundle of light rays impinges on an object with a rough or microscopically structured surface of a size equal or greater than the wavelength, each individual ray encounters a different surface slope and therefore the law of reflection takes effect for a different angle $\theta_i$ to the surface normal at this point. As a result, the bundle of light is diffusely scattered in all directions in the plane of incidence. The amount of diffuse scattering is dependent on the level of roughness or microscopic surface structuring. It is possible for oriented surfaces that the scattering will be anisotropic. The ideal diffuse reflector is a Lambert surface, where an equal amount of light is scattered in each direction of the hemisphere. The surface structure of certain materials (i.e. common in CSP application) leads to directional scattering, where the majority of the individual light rays are still oriented in the general specular direction related to the incidence angle of the light bundle, and only a small amount is scattered in a wide range of angle offsets from the specular direction. This leads to a reflectance distribution peaked in the specular direction and decreasing away from it. [1]
Near-specular (or specular) reflectance

In CSP applications the hemispherical reflectance alone is not enough descriptive: mirrors are used to redirect solar radiation towards a receiver, and only the part reflected in the acceptance-angle 2\(\phi\) of the receiver is intercepted, being \(\phi\) the polar angle defined by the direction of the ideal specular reflected beam and the direction of the admissible maximum dispersion of reflection on the surface. Typically \(\phi \leq 20\) mrad, therefore the reflectance concerning CSP can be referred to as near-specular. Its value is generally less than the hemispherical one, and greater than the genuine specular reflectance, which strictly speaking refers to \(\phi = 0\). For the purpose of simplicity and usefulness, near-specular reflectance is referred to as specular reflectance, always specified with the acceptance angle.

The measured spectral specular reflectance for solar applications is written as \(\rho_{s,\phi}(\lambda, \theta, \phi)\) where \(\rho_{s,\phi}\) is dependent on the wavelength, \(\lambda\), and is function of the incidence angle, \(\theta\), as well as the (half) acceptance angle, \(\phi\), associated with the detector aperture. Alternatively, the specular reflectance is the hemispherical reflectance minus the light scattered outside a specified \(\phi\). [1]

Solar-weighted and UV-weighted reflectance

The solar-weighted reflectance, \(\rho_s\), and the UV-weighted reflectance, \(\rho_{\text{UV}}\), of a mirror represents the convolution of the spectral reflectance function, \(\rho_s(\lambda)\), with the solar irradiance function, \(G_s(\lambda)\), in the proper \(\lambda\) range. Since these functions are generally only known with discrete values, the integration is performed as a summation. Therefore, the solar-weighted or UV-weighted hemispherical reflectance, \(\rho_{s,h}(\lambda, \theta, h)\) or \(\rho_{\text{UV},h}(\lambda, \theta, h)\), and the solar-weighted or UV-weighted specular reflectance, \(\rho_{s,\phi}(\lambda, \theta, \phi)\) or \(\rho_{\text{UV},\phi}(\lambda, \theta, \phi)\), of a solar mirror is calculated using the values of the measured reflectance spectrum, \(\rho_s(h, \theta, \phi)\) or \(\rho_{\text{UV},h}(\lambda, \theta, \phi)\), and the direct solar irradiance spectrum, \(G_s(\lambda)\), at wavelength intervals of \(G_s(\lambda)\) with equations (1.1) and (1.2):

\[
\rho_{s,h}(\lambda, \theta, h) = \frac{\sum_{\lambda_{\text{min}}}^{\lambda_{\text{max}}} \rho_s(\lambda, \theta, h) \cdot G_s(\lambda) \cdot \Delta \lambda}{\sum_{\lambda_{\text{min}}}^{\lambda_{\text{max}}} G_s(\lambda) \cdot \Delta \lambda} \quad \text{for } \lambda = \{\lambda_{\text{min}}, \lambda_{\text{min}} + 5, ..., \lambda_{\text{max}}\} \tag{1.1}
\]

\[
\rho_{s,\phi}(\lambda, \theta, \phi) = \frac{\sum_{\lambda_{\text{min}}}^{\lambda_{\text{max}}} \rho_s(\lambda, \theta, \phi) \cdot G_s(\lambda) \cdot \Delta \lambda}{\sum_{\lambda_{\text{min}}}^{\lambda_{\text{max}}} G_s(\lambda) \cdot \Delta \lambda} \quad \text{for } \lambda = \{\lambda_{\text{min}}, \lambda_{\text{min}} + 5, ..., \lambda_{\text{max}}\} \tag{1.2}
\]

where the \(\lambda_{\text{min}}\) and \(\lambda_{\text{max}}\) must be taken from Table 1.1, according to the type of desired average, and the subscript \(s\) properly set. [1]

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</tr>
<tr>
<td>UVB</td>
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Direct transmittance or near-direct transmittance

Ratio of the radiant flux passing through a material within the solid angle \(2\pi\phi\) (being \(\phi\) the angle of acceptance of the transmitted radiation) around the incident beam direction, to the radiation incident on it.
Hemispherical transmittance

Ratio of the radiant flux passing through a material within the complete hemisphere over its exit surface, to the radiation incident on it.

Solar transmittance

Transmittance spectrum weighted over the solar spectral radiant distribution. The solar transmittance is indicated with the subscript “s” after the transmittance symbol, $\tau_s$. This term can either refer to direct or hemispherical transmittance, which is indicated in a second subscript after the transmittance symbol with d or h, respectively. The solar hemispherical transmittance is represented as $\tau_{s,h}([\lambda_a,\lambda_b], \theta_i, h, T_s)$, being $[\lambda_a,\lambda_b]$ the wavelength range, $\theta_i$ the incidence angle, h the symbol to express the hemispherical property and $T_s$ the temperature. The solar direct transmittance is represented as $\tau_{s,d}([\lambda_a,\lambda_b], \theta_i, d, T_s)$, being $[\lambda_a,\lambda_b]$ the wavelength range, $\theta_i$ the incidence angle, d means direct and $T_s$ the temperature. It is expressed as in equation (1.3) for solar hemispherical transmittance and equation (1.4) for solar direct transmittance (UNE 206009:2013) and (IEC TS 62862-1-1):

$$\tau_{s,h}([\lambda_a,\lambda_b], \theta_i, h, T_s) = \frac{\int_{\lambda_a}^{\lambda_b} \tau_{\lambda,h} (\lambda, \theta_i, h, T_s) G_b(\lambda) d\lambda}{\int_{\lambda_a}^{\lambda_b} G_b(\lambda) d\lambda} \quad (1.3)$$

$$\tau_{s,d}([\lambda_a,\lambda_b], \theta_i, d, T_s) = \frac{\int_{\lambda_a}^{\lambda_b} \tau_{\lambda,d} (\lambda, \theta_i, d, T_s) G_b(\lambda) d\lambda}{\int_{\lambda_a}^{\lambda_b} G_b(\lambda) d\lambda} \quad (1.4)$$

Where:
- $\tau_{\lambda,h}(\lambda, \theta_i, h, T_s)$ is the spectral hemispherical transmittance;
- $\tau_{\lambda,d}(\lambda, \theta_i, d, T_s)$ is the spectral direct transmittance;
- $G_b(\lambda)$ is the spectral solar irradiance.

The range of wavelengths within which the weighting is performed, $[\lambda_a,\lambda_b]$, shall be specified. The wavelength range should be between 300 and 2500nm, optionally between 320 and 2500nm. The temperature $T_s$ taken into consideration is the ambient temperature.\(^1\)\(^2\)

\(^1\) $T_s$ can be omitted if it is the ambient temperature.
\(^2\) For applications using direct solar radiation, the AM (Air Mass) 1.5D spectrum is used to find the direct solar transmittance. The ASTM G173-03 (2012) AM 1.5 solar radiation spectrum shall be used to calculate the solar transmittance.
4. Best practice on degradation monitoring of primary and secondary mirror coating (CIEMAT)

The best approach to quantify the in-service degradation of primary and secondary mirrors currently available is to measure reflectance with portable instruments, typically named as reflectometers. In addition, possible defects appearing in the primary and secondary reflectors must be monitored to assess the degradation of the solar field. It is highly important to remark that in general the in-service degradation of secondary mirrors is a challenging task due to the position of the mirrors (at the top of the solar tower or in the focal line of lineal Fresnel reflectors) and its vicinity to the receiver.

Degradation inspection

Periodic visual inspections are recommended in the solar field (in both sides of the reflectors). When a defect (corrosion spot, delamination, erosion, abrasion, blister, etc.) is detected in a primary or secondary reflector facet, note should be taken to monitor it over time in the next inspections. This inspection should be done at least visually but it is recommended to take pictures when a defect appears. If the same type of defect is detected in several positions, the number of defects must be accounted and at least one of it must be monitored.

Reflectometer features

The following requirements should be considered when selecting or developing a reflectometer [1]:

- If possible, measurement at several (at least three) narrow wavelengths appropriately spaced along the solar spectrum or at a specified wavelength range that accounts for differing wavelength dependent scattering properties.
- Several precise and selectable acceptance apertures or an innovative approach that covers at least a range of acceptance angles from $\phi \geq 0$ mrad to $\phi \leq 20$ mrad.
- Measurement at least at near normal incidence ($\theta_i \leq 15^\circ$), and preferably at two more angles of incidence.
- Preferably absolute measurements, or measurement with a stable, calibrated reference mirror (no diffuse reference coupon or coupon calibrated for gloss measurements).
- If measurements at $\theta_i > 15^\circ$ are possible, the calibration of the reference mirror must be available for the same incidence angles.
- Adjustment options for correcting beam alignment, to account for different mirror thicknesses and surface curvature.
- As the instrument must be portable: high battery autonomy, battery status indicator, light-weight, small compact size, easy to handle, robust and digital data storage.
- All measurements included in the process of obtaining the desired result should be done at the same spot on the sample and with the same instrument (i.e. same light source, detector etc.). Measurement spot size as large as possible, with the option of reducing size in case of interest.
- If possible, non-contact measurement to avoid damaging the surface.
- Stable concerning associated type B uncertainties. These type-B uncertainties should be kept to a minimum.
- No influence by external stray light.
- No risk to human health or environmental hazard involved.
- A coordinate system that is incorporated in the instrument to identify the position of defect points on a mirror and study their evolution over time would be a useful addition for monitoring quality.

Table 1.2 presents a summary of the commercial reflectometers currently marketed [2], [3].

<table>
<thead>
<tr>
<th>Manufacturer</th>
<th>Surface Optics</th>
<th>Device &amp; Services Co</th>
<th>Schmitt Measurement Systems</th>
<th>Abengoa</th>
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<th>CSP Services GmbH</th>
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<td>410 Solar</td>
<td>15R-USB 15R-RGB</td>
<td>μScan™</td>
<td>Condoor</td>
<td>CM-700d/600d</td>
<td>TraCS</td>
<td>PFlex</td>
<td>AVUS</td>
</tr>
<tr>
<td>Measurement principle</td>
<td>Integ. sphere unit where the specular port can be opened</td>
<td>A source lamp and a detector positioned in incidence and outgoing angles</td>
<td>A source lamp and a detector positioned in incidence and outgoing angles</td>
<td>Six optical channels composed by a source lamp and two detectors</td>
<td>Integrating sphere unit where the specular port can be opened</td>
<td>One pyrheliometer for measuring DNI and another looking at the mirror sample</td>
<td>A source lamp and a detector positioned in incidence and outgoing angles</td>
<td></td>
</tr>
<tr>
<td>Measurement type</td>
<td>Hemispheric and diffuse reflectance (specular calculated)</td>
<td>Specular reflectance at selected φ</td>
<td>Bidirectional scatter function, roughness and specular reflectance</td>
<td>Specular reflectance</td>
<td>Hemispherical and diffuse reflectance and colour</td>
<td>Specular reflectance</td>
<td>Specular reflectance</td>
<td></td>
</tr>
<tr>
<td>Light source</td>
<td>Tungsten</td>
<td>LED (USB), white light with filters (RGB)</td>
<td>Class II Laser</td>
<td>Six LED</td>
<td>Xenon</td>
<td>Sun</td>
<td>LED</td>
<td></td>
</tr>
<tr>
<td>Incidence angle, θi (º)</td>
<td>20</td>
<td>15</td>
<td>25</td>
<td>12</td>
<td>8</td>
<td>15</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Beam spot size (diameter in mm)</td>
<td>6.35</td>
<td>10.00</td>
<td>1.00</td>
<td>1.00</td>
<td>3 to 8 (700d model)</td>
<td>16</td>
<td>10.00</td>
<td>*</td>
</tr>
<tr>
<td>Wavelength range, λ (nm)</td>
<td>Seven bands between 300 and 2500</td>
<td>Peak at 660 (15R-USB) 460, 550, 650 720 (15R-RGB)</td>
<td>Peak at 670</td>
<td>435, 525, 650, 780, 940, 1050</td>
<td>400-700</td>
<td>Integrated full solar spectrum</td>
<td>631 (optional 455, 533, 660)</td>
<td>660</td>
</tr>
<tr>
<td>Acceptance angle, φ (mrad)</td>
<td>52.4</td>
<td>2.3 (15R-RGB only), 3.5, 7.5, 12.5, 23.0</td>
<td>*</td>
<td>290</td>
<td>*</td>
<td>13.6</td>
<td>*</td>
<td>51, 23, 12.5, 7.5</td>
</tr>
<tr>
<td>Accuracy (reflectance units)</td>
<td>±0.020</td>
<td>*</td>
<td>±0.020</td>
<td>±0.002</td>
<td>*</td>
<td>±0.018</td>
<td>±0.01</td>
<td>*</td>
</tr>
<tr>
<td>Repeatability</td>
<td>±0.002</td>
<td>±0.002</td>
<td>±0.005</td>
<td>±0.002</td>
<td>±0.002</td>
<td>*</td>
<td>±0.005</td>
<td>±0.005</td>
</tr>
<tr>
<td>(reflectance units)</td>
<td>0.005</td>
<td>±0.001</td>
<td>±0.001</td>
<td>±0.001</td>
<td>±0.001</td>
<td>±0.001</td>
<td></td>
<td></td>
</tr>
<tr>
<td>---------------------</td>
<td>-------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resolution (reflectance units)</td>
<td>*</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adaptable to mirror curvature</td>
<td>Yes, 15.24 mm ratio minimum</td>
<td>Yes, 114.3 mm ratio minimum</td>
<td>No</td>
<td>No</td>
<td>limited</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Suitable for 1st and 2nd surface mirrors</td>
<td>*</td>
<td>No (chopped light source)</td>
<td>Yes</td>
<td>No (synchronous detection at modulated frequency)</td>
<td>No (pulsed light source)</td>
<td>Requires DNI &gt; 200W/m² for measurement</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Influence of external light</td>
<td>*</td>
<td>No (chopped light source)</td>
<td>Yes</td>
<td>No (synchronous detection at modulated frequency)</td>
<td>No (pulsed light source)</td>
<td>Requires DNI &gt; 200W/m² for measurement</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Weight (kg)</td>
<td>2.13</td>
<td>1.10</td>
<td>2.2</td>
<td>1.40</td>
<td>0.55</td>
<td>*</td>
<td>*</td>
<td>*</td>
</tr>
<tr>
<td>Operating temp. (ºC)</td>
<td>0 - 40</td>
<td>0 - 50</td>
<td>-10 - 45</td>
<td>0 - 55</td>
<td>5 - 40</td>
<td>-20 – 50</td>
<td>-15 - 60</td>
<td>*</td>
</tr>
<tr>
<td>Autonomy</td>
<td>2 h</td>
<td>49-52 h</td>
<td>5 h</td>
<td>1200 measurements</td>
<td>2000 measurements</td>
<td></td>
<td>*</td>
<td>&gt;24 h</td>
</tr>
<tr>
<td>Average time needed for a measurement (s)</td>
<td>10 s</td>
<td>10 s</td>
<td>8 s</td>
<td>8 s</td>
<td>*</td>
<td>10 m</td>
<td>8</td>
<td>*</td>
</tr>
<tr>
<td>Level of required experience of the operator</td>
<td>On site: high (maintaining the seal with the mirror is highly prone to operator error) Data evaluation: medium</td>
<td>On site: high (optical alignment requires an experienced operator) Data evaluation: low</td>
<td>On site: low Data evaluation: medium</td>
<td>On site: low (very little room for operator error) Data evaluation: medium</td>
<td>*</td>
<td>On site: low Data evaluation: high</td>
<td>On site: low (insensitive and robust against slight tilt or twist of the instrument) Data evaluation: medium</td>
<td>Automatic process</td>
</tr>
<tr>
<td>Type of calibration</td>
<td>Two external reference mirrors</td>
<td>One external reference mirror</td>
<td>One external reference mirror</td>
<td>One external reference mirror</td>
<td>*</td>
<td>Cleanliness: sample mirror in clean state Reflectance: reference mirror</td>
<td>Black reference (offset) and one external reference mirror</td>
<td>One external reference mirror</td>
</tr>
<tr>
<td>Beam alignment</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Optical, using pyrheliometer pinholes</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

**Cleaning procedure**

To avoid any influence of the mirror soiling, the mirror’s front surface should be cleaned very carefully prior to measurement (or visual inspection) according to the manufacturer’s recommendation or with compressed air (free of particles and oil). In case of remaining dust or soil after a visual inspection, a soft lens tissue and demineralized water will be employed. Abrasive or solvent agents that may change the properties of the reflector shall never be employed. In addition, special care must be taken to avoid any contamination after the cleaning due to a negligent manipulation. The reflector surface may only be touched with gloves.

If the mirrors cannot be cleaned sufficiently with the normal cleaning procedure because of heavy soiling or because air-blown dirt has bonded and baked onto the mirror surface, slightly more aggressive
Methods may need to be used. Depending on the type of solar reflector, contact washing with a cotton swap and an extremely dilute solution of a mild detergent and demineralized water (1/100) followed by a copious rinse with demineralized water can be used. Careful utilization of ethyl alcohol can be used for glass, protected aluminium, and some front surface mirrors. Isopropanol is not advised because it leaves a residual coating which smears on the mirror. Many alcohols (e.g., toluene, acetone benzene) are not advised for use with silvered polymers because the alcohol can soften and damage the polymer surface. Commercial glass cleaner and chlorine- and ammonia-based cleaners are not recommended with sensitive metals like silver. If a smear is left on the mirror, it should be carefully removed with demineralized water.

The samples should be allowed sufficient time to dry (i.e., overnight), particularly if the mirror’s surface can absorb water (i.e., silvered polymers) during cleaning. Any remaining dust should be removed with pressurized air. The sample should be free of grease and particles and perfectly dry before measurement.

It is important to remark that the cleaning procedure included in this section was specifically developed for laboratory measurements [1]. Consequently, it could happen that this methodology cannot be applied in a solar field due to practical reasons (specially in secondary mirrors). If this is the case, the cleaning method to be used should guarantee the removal of the soiling as much as possible.

**Reflectance measurements**

As the goal is to monitor the time behavior of the reflectance during in service operation, the samples shall be measured in the exact same positions for each analysis. A mask or stoppers may be used to easily find the same measurement position again after exposure.

To monitor the aging, it might be sufficient to measure the specular reflectance at one defined wavelength in the range $\lambda=[400, 700]$ nm, $\theta \leq 15^\circ$ and $\varphi$ in the range of $\varphi \geq 0$ to $\varphi < 20$ mrad. The reflectance loss is computed by subtracting the initial value from the reflectance after exposure.

As a minimum, 5 monochromatic specular measurements shall be taken on each reflector facet. The 5 monochromatic measurements obtained with a reflectometer shall be taken in the center of the sample and close to the 4 corners of the facet. The measurement shall not be taken closer than 10 mm to the facet edge.

**Recommended number of reflectance measurements (information provided by BSII, subjected to confidentiality)**

According to the current procedure applied by BSII in the solar field heliostats, for each mirror reflectance is measured at 4 different locations over the mirror surface with the reflectance measurement device. Preferably, 1 heliostat out of 500 is measured in a solar field of 50,000 heliostats. Measurements are repeated every day at the same heliostats and preferably same location. It must be noted that this procedure is site specific, both as per section of the solar field, pending topography and typical wind.

**Camera based reflectance and degradation measurements**
Reflectometer measurements of degradation and reflectance can be accompanied by camera based measurements, extending the resolution of samples taken. Camera based methods allow for relative measurements with a homogeneously illuminated reference target of the clear sky [4]. With the well calibrated camera pictures of this reference target are taken via the reflector. The translation from relative measurements to absolute values of reflectance or cleanliness is done with the simplified relation for near normal incidence and view configuration:

$$\rho_{i,\phi} = m_{\phi} \rho_{\text{Ref}} \frac{\hat{C}_i L_{\text{Ref}}(d_{\text{Ref}})}{\hat{C}_{\text{Ref}} L_i a(d_i)} + \Delta \rho_{\phi}. \quad (1.5)$$

$\hat{C}_i$ is the corrected camera image at any discrete sample point, $L_{\text{Ref}}/L_i$ accounts for the differences in brightness of the reference target, ideally with a value of 1, $a(d_{\text{Ref}})/a(d_i)$ accounts equally for differing attenuation factors in case of very distant measurement points. $\rho_{\text{Ref}}$ is the reflectance measured with a reflectometer at the reference position and $\hat{C}_{\text{Ref}}$ holds the camera count (intensity value) taken at the reference position. The factor $m_{\phi}$ and the offset $\Delta \rho_{\phi}$ introduce an adaption of the acceptance angle of the two measurement techniques involved. For measurements of degradation introduced by the silver or paint layers these are negligible. For effects involving scattering these are important. Especially in the case of cleanliness measurements, the correlation is dependent on the type of soil. Furthermore reference target size and relative position must be taken into account.

For camera based measurements of degradation and cleanliness, proper camera calibration and control of light conditions is key for valuable measurements.

- Dark noise correction;
- Flat field correction;
- Correction of linearity of the camera chip.
- Aperture / lens shading / zoom have influence in flat field correction

Control of light conditions is a challenging task for measurements in the solar field. Measurements with an artificially homogeneously illuminated reference target can be performed at night to reduce the influence of changing light conditions during daytime. However, providing a homogeneous target remains challenging. Measurements at daytime require the deflection of a homogeneous part of the sky, resulting in a hemispherical measurement of reflectance.

The spectral components are accounted for by the use of filters for the range of wavelegths $[\lambda_a, \lambda_b]$ in front of the camera optics. The incidence angle of the camera view should be chosen to accord with the incidence angle of the light source in the reference measurement of the reflectometer (e.g. at $\theta_i=8^\circ$). Due to the reversibility of the path of light, the acceptance angle is defined by the light source in this technique. It must be noted that, depending on the curvature of the reflector and the camera distance to the distinct point of discretization, different angles of incidence of the camera view must be accounted for. The technique is recommended for flat reflectors and reflectors with little curvature.

**Reporting**

- Visual inspection (in both sides of the reflectors)

The following information must be included in the defects report:

- Date and time;
- Exact position of the defect;
- Type of defect;
- Camera used;
- Operator name;
- Cleaning method employed before the inspection.

- Reflectance measurements

Following information must be included in the reflectance measurement report:

- Date and time of the measurement campaign;
- Exact position of the reflector facet measured, with respect to the solar field;
- If possible, coordinates of the measurement spots in the reflector facet;
- Measurement instrument used (including all its features);
- Operator name;
- Cleaning method employed before the measurements.
5. Best practice on degradation monitoring of ST absorber coating (DLR)

The absorber coating receives the concentrated sunlight from the solar field and needs to withstand high thermal stresses in demanding desert conditions. Periodic monitoring of the absorber coating degradation is essential for the profitability of solar tower plants. The following monitoring methods are possible:

In-situ techniques

Visual inspection
- Identification of delamination/peeling/flaking/oxidation;
- Measurement technique: camera with telephoto lens, drone or stage for tower inspection.

Local measurement of optical properties with handheld devices
- Measurement of solar absorptance and thermal emittance at selected spots in discrete spectral bands, at ambient temperature, typically between 0 and 50 °C.
- Possible instruments:
  - BSII: Surface Optics 410-Vis-IR Portable Solar Reflectometer and Emissiometer;
  - Fraunhofer Spin-Off: Optosol GmbH, Alphameter & Emissiometer;
  - Typical error: 0.2 p.p for solar absorptance, 2% for thermal emittance.

Table 1.3: Surface Optics 410-Vis-IR characteristics.

<table>
<thead>
<tr>
<th>410 solar Sub-spectral ranges</th>
<th>ET-100 Sub-spectral ranges</th>
</tr>
</thead>
<tbody>
<tr>
<td>350-380nm</td>
<td>1.5 to 2 μm</td>
</tr>
<tr>
<td>400-540nm</td>
<td>2 to 3.5 μm</td>
</tr>
<tr>
<td>480-600nm</td>
<td>3 to 4 μm</td>
</tr>
<tr>
<td>590-720nm</td>
<td>4 to 5 μm</td>
</tr>
<tr>
<td>700-1100nm</td>
<td>5 to 10.5 μm</td>
</tr>
<tr>
<td>1000-1700nm</td>
<td>10.5 to 21 μm</td>
</tr>
<tr>
<td>1700-2500nm</td>
<td></td>
</tr>
</tbody>
</table>

- Fraunhofer Spin-Off: Optosol GmbH, Alphameter & Emissiometer;
- Typical error: 0.2 p.p for solar absorptance, 2% for thermal emittance.

Measurement of temperature distribution using IR-cameras

Several infrared cameras are mounted on the ground around the receiver circumference to monitor its temperature distribution. These cameras are mounted in protective cases with temperature control, using athermalized objectives for accurate temperature measurement.
- Identification of possible hot spots (local overheating) according to operator experience;
- Identification of delamination / changes in coating thickness;
- Possible instruments: solarblind IR camera
Industrial FLIR camera (e.g. Thermovision or similar), LWIR range (8-12 um);
Alternative: Industrial Infratec camera, VarioCAM HD Head900;
Long range requires both a HD chip (resolution> 640x480 pixels) and teleobjective (f > 200 mm).

Current calibration procedure [5] involves a 1m² flat target with a reference coating similar to the applied receiver coating, heated to a reference temperature, below the maximal operating temperature of the receiver. This target works similarly to an extended blackbody calibrator, although the temperature homogeneity may not be as well controlled as for a precision blackbody calibrator. The reference temperature of the target is measured with a set of calibrated thermocouples, at least 3 units for a redundant measurement.

The target is mounted in the thermographic scene. As it stands on the same plane as the receiver, atmospheric influences are corrected, applying an efficient emissivity factor. However, this method does not necessarily account for local variations of the emittance caused by receiver degradation, nor does it account for geometrical corrections (size of source effect, curvature of the measurement object).

**Destructive techniques**

**Local measurement of solar absorptance on small absorber sample**

Prior to optical measurements, absorber samples should be cleaned with dry pressurized air. Samples should be handled with care, using clean latex gloves.

- Spectral measurement of absorptance with high precision (0.5%-p uncertainty) in the wavelength range 250-2500nm;
- Possible equipment: Spectrophotometer
  - Perkin Elmer Lambda 950 or 1050 with integrating sphere;
  - Alternatives: Bruker Vertex 80 or Cary500;
  - Incidence angle: 8°, integrating sphere diameter: 150 mm; white diffuse background (Spectralon);
- Measurement spot: around 10 x 10 mm²;
- Flat or curved samples up to 120 x 120 mm².

**Local measurement of thermal emittance on small absorber sample**

Prior to optical measurements, absorber samples should be cleaned with dry pressurized air. Samples should be handled with care, using clean latex gloves.

- Spectral measurement of emittance with high precision (1%-p uncertainty) in the wavelength range 2 – 16 µm, optionally up to 20 or 25 µm;
- Possible equipment: FTIR Spectrophotometer
  - Perkin FTIR with PIKE Technologies Integrating Sphere, liquid nitrogen cooling required;
  - Alternative: Bruker Vertex 80 Surface Optics HDR100 coupled with Nicolet FTIR;
Incidence angle: 8-12°, integrating sphere diameter: 76.2 mm or larger, Background: Infragold;

- Measurement spot: 10x10 mm²;
- Flat or curved samples up to 120 x 120 mm².
6. Best practice on degradation monitoring of glass envelope AR coatings for CSP (CIEMAT)

In this method, measurements of spectral near normal-hemispherical transmittance are made over the spectral range from 300 to 2500 nm with an integrating sphere spectrophotometer. The method presented here is based in the ASTM standard E903-12.

The solar transmittance, $\tau_s$, is obtained by calculating a weighted average with a standard solar spectral irradiance according to the definitions contained in IEC TS 62862-1-1.

Solar transmittance is the key parameter to evaluate the optimal performance of the AR coating of solar glass envelopes. Furthermore, variations in the value of this parameter could point out some degradation on the antireflective coating. This test is a destructive method, meaning that a small piece needs to be cut out of the receiver tube and analysed in the laboratory. The typical sample size is 10 x 10 cm².

**Spectrophotometer**

A double beam spectrophotometer with an integrating sphere attachment capable of measuring the spectral characteristics of the test specimen or material over the solar spectral region from 300 to 2500 nm is required. The design shall be such that the specimen may be placed in direct contact with the sphere aperture, so that the incident radiation is within 8 ±2 of perpendicularity to the plane of the specimen. In this way, the specular component of the reflected energy is not lost through an aperture. Ambient light must be prevented from entering the sphere.

The interior of the integrating sphere shall be finished with a stable highly reflecting and diffusing coating. Materials as polytetrafluoroethylene and BaSO$_4$ satisfy the required properties. The ratio of the port area to the sphere wall plus port area should be lower than 4%. This low port fraction ensures good integration of the sample signal before it reaches the sphere’s detector. Spheres higher or equal than 150 mm are preferred.

**Standards**

In general, both reference and working (comparison) standards are required. Reference standards are the primary standard for the calibration of instruments and working standards. Working standards are used in the daily operation of the instrument to provide comparison curves for data reduction. They should be handled with care and stored in a clean, safe manner. They should be cleaned according to the manufacturer's specifications, renewed, or replaced if degradation is noticeable. Avoid touching the optical surfaces. Only clean soft cloth gloves should be worn for handling the standards.

For our case, transmittance measurements, incident radiation shall be used as the standard relative to which the transmitted light is evaluated. For very high transmitting specimens, a zero line correction is required. Light traps, diffusing black material or blocking the beam can be used for this purpose.

**Test specimens**

The size of test specimens required depends on the dimensions of the integrating sphere. The specimen must be large enough to cover the aperture of the sphere. For curves specimens, the part that covers the aperture of the sphere should be essentially plane. In this case, a special holder that allows the perfect adjustment between the curve sample and the aperture of the sphere has to be used.
**Procedure**

**Calibration**

Working standards should be recalibrated periodically, once a year at least. About the spectrophotometer, linearity and wavelength scales should be calibrated according to the manufacturer recommendations. Check on calibration annually.

**Measurement**

For all the measurements, at least one value each 10 nm has to be recorded in the 300-1500 nm range. Between 1500nm and 2500nm, the measurement interval could be 50nm. It is recommended to record 100 % and zero line curves every hour during testing.

Cover the specimen and reference ports at the rear of the sphere with surfaces having the same coating and optical properties as the sphere walls when measuring transmittance. Record spectral curves without any specimen in place and then with the specimen over the specimen beam entrance port of the sphere. Calculate the spectral transmittance as:

\[
\tau(\lambda) = \frac{(S_\lambda - Z_\lambda)}{(100_\lambda - Z_\lambda)}
\]

where:
- \( S_\lambda \): signal recorded with the specimen over the entrance port
- \( Z_\lambda \): zero line reading with the specimen beam blocked with an opaque material, and
- \( 100_\lambda \): line recorded with no specimen over the specimen beam entrance port.

**Calculation of solar transmittance**

Solar energy transmittance is calculated by weighting the spectral transmittance measured over the corresponding solar spectrum, according the equations showed previously in the Terms and Definitions section. The temperature \( T_s \) taken into consideration is the ambient temperature (25°C±2°C) (UNE 206009:2013). The ASTM G173-03 (2012) AM 1.5D solar radiation spectrum shall be used for calculations.

**Reporting**

The report shall include the following:
- Complete identification of the material tested, specimen size and thickness, surface contour if any
- Solar transmittance values determined to the nearest 0.001 unit or 0.1 %.
- Identification of the instrument used. Manufacturer’s name and model number including modifications, accessories, integrating sphere size, are sufficient for a commercial instrument. Other instruments must be described in detail including estimations of their accuracy.
- Complete identification of the standards used in the measurements.
- Solar spectral irradiance used for computation of the solar optical property.

**7. Best practice on degradation monitoring of corrosion-resistant steel**
coating (UCM, DFI)

Molten salt exposure tests in laboratory

Laboratory tests can provide useful data on the corrosion behavior of uncoated and coated alloys in molten salt. The salt mixture can be prepared from NaNO₃ and KNO₃ salts e.g. 60 wt.% and 40 wt.% ratio respectively for the solar salt. In order to investigate the influence of chloride and sulphate impurities, NaCl and Na₂SO₄ can be added to the mixture in desired amounts (e.g. 300 or 500 ppm). A surface pre-treatment (e.g. grid-blasting or polishing) of the samples is suggested in order to maintain an identical surface finish for the samples prior to exposure. As a matter of fact, sample geometry, surface treatment as well as the amount of salt mixture per sample surface area are standardized by ISO 17245:2015. After surface pre-treatment, the samples can be cleaned in ultrasonic bath followed by the determination of their surface area using a calliper and initial weight using a precision balance. The laboratory tests can be conducted under three different conditions: (i) static, (ii) thermocyclic and (iii) dynamic.

Static tests are conducted to evaluate the scaling behavior of alloys in isothermal conditions. For that purpose, the samples are initially placed in individual alumina crucibles which are then filled with the salt mixture and the crucible is closed with an alumina lid. Thereafter, the crucibles are placed in a horizontal quartz tube furnace (see Figure 1.1) or in a muffle furnace with covered resistances in order to not damage the resistances with nitrous gases, and heated up the exposure temperature which can lie within the range between 560-600°C. The calibration of the furnace prior to exposure is also strongly recommended in order to avoid temperature deviations during testing and to identify the dimensions of the effective area where the temperature is homogeneous. The heating can be conducted with 10°C/min up to 230°C followed by a slower heating rate (e.g. 2°C/min) to 290°C to reach a homogenous mixture of the solar salt and again with 10°C/min to the exposure temperature, followed by a dwell period, after which the samples are removed from hot furnace and removed carefully from the liquid salt mixture. Due to the decomposition of nitrate salts leading to the formation of nitrous gases, specific safety measures of the related laboratory should be carefully followed most importantly the particular respiratory protective equipment whilst removing the crucibles from the furnace. Due to the same evaporation reason, crucibles need to be replenished with salts periodically. Subsequent to their cooling down to room temperature, samples can be rinsed with hot distilled water in order to remove salt residues and the net specific weight change can be determined using a precision weighing balance. It should be noted that net specific weight change provide adequate information of the behavior of coated samples but does not provide any information on the spallation kinetics of the uncoated samples. As corrosion in molten salt results from the competition between reactions of dissolution and formation of corrosion products, the weight changes have to be considered with caution. Uncoated samples can be descaled by using acid pickling in order to accurately measure the material loss rather than the scale growth according to the ISO8407:2009 standard: Corrosion of Metals and alloys. Removal of corrosion products from corrosion test specimens. Judicious chemical solution has to be used depending on the nature of the base substrate in order to remove corrosion products without affecting the base material. Samples are then weighted after corrosion products removal.
Figure 1.1: Schematic illustration of the corrosion test rig used at DFI for static molten salt exposure.

Under CSP service conditions, alloys used as structural materials in receiver tubes are in contact with molten solar salt having different temperatures. Thermocycling testing is a more aggressive environment than isothermal test as the Thermal Expansion Coefficient (CTE) varies with the temperature cycle and causes a higher spallation rate due to mechanical stresses at the oxide/substrate interface. Thermocyclic exposure tests can be used to simulate the plant conditions which involve the temperature changes of the molten salt between the hot and cold storage tanks. The exposure temperature and the minimum temperature can be selected according to plant conditions particularly the temperature in the hot (around 560°C) and cold (around 290°C) storage tanks. An example of temperature-time profile used in laboratory is presented in Figure 1.2. To reach high cooling rates (around 10°C/min between 580°C and 500°C, 6°C/min between 500°C and 400°C and 4°C/min between 400°C and 300°C), a specific muffle furnace with an integrated cooling system is required. Same immersion procedure than in static conditions can be applied for thermocyclic exposure in molten nitrate salt. Samples are heated up to exposure temperature and kept at this temperature for a selected time period and cooled down to the minimum temperature of the exposure. Samples are removed after different time intervals, cooled down to room temperature, washed with hot distilled water and weighted.

Figure 1.2: Temperature-time profile of the thermocyclic exposure tests conducted at INTA.

CSP service conditions include a continuous molten salt flow which cannot be investigated with laboratory immersion tests. The dynamic flow of the salt can lead to erosion damage to oxide scales grown on alloys and increase the depletion of the stable oxide former e.g. Cr or Al and thus result in an
earlier breakaway of the alloy than expected. Dynamic tests (e.g. thermal convection loop [6]) can be employed in order to simulate the influence of the molten nitrate salt flow on the scaling behavior of alloys. To this end, samples are introduced in a sample holder within a facility in contact with the salt mixture. The equipment, patented under the reference code WO2016102719, enables degradation tests of materials in contact with molten mediums to be performed, remaining possible the simulation of a thermocycling process and the maintenance of stable conditions during whole study. This equipment assures a continuous circulation of the molten salt on the specimens under study, maintaining the selected temperature over the entire test. It should be underlined that samples are tested inside a chamber of alumina that avoids the contact between samples and the material in which the device is made of.

The dynamic test facility allows a constant measure of the temperature and set a suitable velocity of the molten salt flux, depending of the requirements (e.g. the flow velocity in areas near to pipe bends and valves in the current CSP plants are ranged between 0.2 m·s⁻¹ and 0.5 m·s⁻¹). On the other hand, the samples are placed into the facility so that the flow is parallel to them. That allows us to simulate the most common angle attack of the salt flow in CSP plants when the salt circulates through steel tubes.

After molten salt exposure, the samples can be cross-sectioned using conventional metallographic methods involving galvanic Ni-plating, mounting in epoxy resin, grinding using SiC papers and polishing via diamond suspensions down to 1 µm. Analytical characterization methods including light optical microscopy (LOM), scanning electron microscopy (SEM), electron dispersed spectroscopy (EDS) or electron-probe micro analysis (EPMA) and X-ray diffraction (XRD) can be employed to characterize the corrosion products after exposure.

**Online corrosion monitoring system**

The conventional methods used for studying corrosion caused by molten salt such as optical microscopy (OM), scanning electron microscopy energy/dispersive X-ray spectroscopy (SEM/EDS), and X-Ray Diffraction (XRD) cannot be used in real-time. The general procedure of the above techniques involves taking the metal sample from the molten salt at a certain temperature followed by performing a gravimetric analysis after cooling. Subsequently, microstructural characteristics and composition information are used to determine the corrosion mechanism. These asynchronous techniques for corrosion analysis are feasible but tedious and time-consuming because of the pre-processing required and the repeated sampling steps. Thus, these analytical techniques are not the optimal methods for corrosion analysis because the lack of the immediacy when monitoring the real-time reaction state. A better understanding of the process requires a monitoring system that records corrosion rates in real-time. In this regard, electrochemical impedance spectroscopy (EIS) is considered a powerful technique for characterising a wide variety of electrochemical systems and for determining the contribution of electrolytic processes in these types of systems. Thus, it can be used to investigate the dynamics of linked or mobile charges on the volume of interface regions and assumes that the behavior of steel in contact with molten salt can be represented by simple circuits consisting of resistance, capacitance and inductance elements under an alternating current. When an alternating current potential is applied to the system, the resulting current is measured, the impedance associated to these elements being obtained from an expression analogous to Ohm’s law.

To this end, as shown in Figure 1.2, specimens of the specific steel should spot welded to a wire made by a resistant alloy for electric connection. The sample-wire connection should be coated with a ceramic slurry and the assembly inserted into a rod of alumina ceramic sealed with the same ceramic mixture. The purpose of this ceramic material is to isolate the working area and protect the sample-wire joint from the molten salts. A two-electrode system (see Figure 1.2) is employed for the EIS measurements: the first being the working electrode (WE), with the second electrode serving as auxiliary electrode (AE) and as
reference electrode (RE). The electrodes should be connected to an electrochemical instrument and it is recommended to use an amplitude of the input sinusoidal perturbation signal voltage of 10 mV with a sweep frequency from 50 kHz to 10 mHz. Fitting of the impedance data settings and simulations should be performed by an appropriate software (e.g. the Zview software). One important parameter in these measurements is the surface area of each electrode in contact with the molten salt. It is important to highlight, that this system is patented under the reference code WO2017046427.

Thus, the electrodes should be immersed in the molten salt at the required temperature and measurements should be taken continuously. This will allow monitoring the corrosion process of the steel under study, being possible to assess not only the corrosion mechanism (generalized corrosion, protective corrosion layer, porous layer, and localized corrosion) (see Figure 1.3), but also the corrosion rate (using Stern-Geary equation and the ASTM-G102 Standard Practice).
8. References


Chapter 2: D6.5 Best practice on O&M of Functional Materials in the Solar Field

1. Scope and objective

This project focusses on raising the lifetime of five key functional materials for concentrated solar power (CSP) technologies: 1) protective and anti-soiling coatings for primary reflectors, 2) very high-reflective surfaces for heliostats, 3) high-temperature secondary reflectors, 4) receiver coatings, 5) corrosion resistant high temperature metals and coatings for molten salts. For this purpose, the project brings together a broad consortium formed of leading industry partners, SMEs and research institutes of the concentrated solar thermal and material science sector. The project scope has been significantly shaped by the leading Engineering, Procurement and Construction (EPC) of ST technology BSII. This unique constellation permits a direct transfer of the obtained results in RAISELIFE into new commercial CSP plants within less than 5 years.

The gained experience on accelerated testing methodologies, degradation monitoring and measurement techniques as well as sample treatment and correlation to in-service results will be summarized in a catalogue of good practices. This catalogue of good practices will be developed by the partners to reduce in-service degradation and will be made available to the CSP community by transferring it to national and international standardization committees and feeding the results into working groups like SolarPaces Task III.

This catalogue will make use of the results of WP 1 to 5 and will include a compilation of good practices on: (a) the detection and monitoring of degradation during service and operation in the field as well as after accelerated testing, derived from agreements reached between all testing institutions/partners, (b) application, operation and maintenance of functional materials and coatings, e.g. information on cleaning, collected and derived from recommendations of coating and operating partners, (c) economic impacts and economic viability of different measures influencing the in-service degradation, which will make use of both practical experiences of industrial partners and results from the economic assessments of T5.3, (d) testing protocols and accelerated aging procedures to reproduce outdoor effects, derived from the knowledge and results of the partners performing accelerated aging tests, (e) good practices and a protocol for evaluating corrosion in molten salt environments will be developed in the frame of WP4, (f) good practice on steel selection for CSP.

In particular, this deliverable is devoted to the best practice on O&M of functional materials in the solar field. This means the critical information about the possible tasks to be applied during the O&M of the plant that could affect the durability of the studied materials. Once those tasks are identified by the plant operators, the materials developers and testers will recommend the best way to proceed to avoid any possible damage on the materials.
2. **Normative references**

- IEC 61215: Terrestrial photovoltaic (PV) modules - Design qualification and type approval
- UNE EN 12975: Thermal solar systems and components - Solar collectors - Part 2: Test methods
- ASTM D4417-93: Standard test methods for field measurement of surface profile of blast cleaned steel
- ASTM D7127: Standard test method for measurement of surface roughness of abrasive blast cleaned metal surfaces using a portable stylus instrument
- SSPC-PA 1: Shop field and maintenance painting of steel
- SSPC-SP11: Power tool cleaning to bare metal
- ASTM D4414-95: Standard practice for measurement of wet film thickness by notch gages
3. Best practices on O&M of primary reflectors in the solar field

In this section, the best practices on O&M of primary reflectors in the solar field are explained. The goal is to provide plant operators with useful information and advises to be followed when applied the O&M tasks affecting the durability of primary reflectors.

3.1. Solar Field Safety

In all solar field maintenance, safety should be a high priority. Safety must be part of general O&M planning as well as planning for any specific activity.

3.1.1. When is it Safe to Work?

The following rules must be strictly followed before any O&M task is accomplished:

- Work in the solar field should stop if there are high winds, dust or rain storms or other unsafe environmental conditions.
- Work in the solar field is possible during operation. Use a maintenance mode and create paths as explained below to create safe and convenient working areas for the maintenance personnel.
- Ensure that the control room operators are aware of all personnel in the field and that they have 2-way radio or equivalent communications methods. Report upon entry and exit from the field.

3.1.2. Personal Protective Equipment (PPE)

All personnel in the solar field should wear appropriate PPE. This may vary depending on the local conditions. The table below is provided as a guideline.

<table>
<thead>
<tr>
<th>Clothing</th>
<th>Long sleeves CPF45</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shoes</td>
<td>EN ISO 20345, S3</td>
</tr>
<tr>
<td>Sun Safety Glasses</td>
<td>EN 166-FT ANSI Z87-1 Normal work VLT 11% Shaded area VLT 15% High exposures VLT 7%</td>
</tr>
<tr>
<td>Hard Hat</td>
<td>ANSI Z89.1, EN 397,</td>
</tr>
</tbody>
</table>

In addition, if snakes are present, then high chaps should be worn. Finally, sun screen is highly recommended.

3.1.3. Driving in the solar field

The following rules must be followed when driving in the solar field:

- All drivers must hold a valid driving license suitable to the vehicle they drive. Driver must be trained and approved to drive the specific vehicle by the plant EHS and SF manager.
• Driving on site in accordance to local traffic laws and regulation. The drivers shall obey all traffic sights installed on site. Maximum speed on unpaved areas in the solar field should be set at about 15 km/h; speed on paved roads may be higher according to site decision.

• Drivers or operators of a vehicle on site should take extra care while operating vehicle on site due to the joint use and interface of human and vehicle at the same area.

• All vehicles are to be tested daily by the driver for the safety systems light system breaks and operational systems. Seatbelts, where fitted, shall be fastened when the vehicle is being moved.

• The use of vehicles in accordance to manufacturer instructions (the instructions must be understood and signed prior to the use of the vehicle).

• While driving a vehicle, it is forbidden to use or to hold a mobile phone or any other distraction from the road or driving.

• Prior to vehicles entering the solar field the traffic routes need to be planned and to be examined by the work foreman to detect any hazards or obstacles.

• Reversing with a trailer in the SF heliostats area is prohibited.

• Avoid driving in the SF after rain, which may result in slippery conditions.

• Establish parking guidelines so that parked vehicles do not interfere with the passage of other vehicles or personnel or with the proper operation of the heliostats. For instance, parking should be on the side of main roads and not in the solar field where possible. If necessary to park in the solar field, park at least 3.5 m from any heliostat pylons.

3.2. Replacement and repair of components

This section does not refer to the replacement of components at the solar field during the plant commissioning, nor the disassembling of the whole heliostat/collector, which would otherwise refer to heliostat/collector installation instructions. When a heliostat/collector component (parabolic-trough receiver, heliostat engine, etc) is deteriorated or broken, the repair or replacement must be accomplished with extreme care to avoid any interference or damage of the primary reflectors. The same applies to the reflector facets repair or replacement because in this case the maintenance operation must avoid any interaction with the neighbour facets.

The main risk in any case is the mirror breakage. The following best practises are recommended to avoid the mirror breakage:

• Verify that the mirror support is perfectly clean and flat. This means no remaining piece of the old mirror on the frame, no remaining glue spots, etc. All over-thicknesses of the frame may induce glass distortion and breakage or a less efficient fixation of the mirror.

• Check if the glass is free of small damage before positioning. A small damage on the edge may induce breakage.

• Avoid glass bending during the positioning. If glass has to be slightly bent, refer to the glass supplier. Maximum radius bending will be defined according to glass thickness, optional glass temperature treatment and glass composition.

• Use the appropriate elevator/engine to position the glass on the supports, considering safety rules of the solar field. Some solar fields are using large mirrors that cannot be positioned manually due
to the glass weight and risks of breakage. Some glass manufacturers recommend to avoid manual operation if all dimension of the glass exceed 0.8 m.

3.3. Mirror replacement on heliostat fields

Mirror replacement is highly dependent upon the heliostat design. Taking replacement needs into account in the design phase is critical, as otherwise it may be very difficult to carry out on site. One important consideration is timing. Several factors should be considered:

- The number of broken mirrors and how much reflective surface is actually missing determines the impact on performance. If replacement is easy, then it can be done on the fly. But if not, then it should be planned periodically, as the reflective surface impacted reaches a specific threshold.

- Broken mirrors can mean anything from a small missing corner or a crack to a full pane missing. Depending on the heliostat structure, if enough mirror surface is missing, it may cause an imbalance in the heliostat which will affect its overall position and put undue pressure on various mechanical elements and motors. Thus large breakage is more serious than minor breakage.

- Typically, the mirror replacement activity requires a variety of jigs and lifts, such that it should be done for a large number of mirrors at one time. This can typically be part of an annual maintenance shutdown.

The first task is identifying heliostats with broken mirrors and recording the amount of breakage. The plant should have a maintenance system capable of recording this information by heliostat tag.

Planning for the repairs depends on the system design.

- If the mirrors are individually attached (e.g. via rivets or screws in mirror pads), then they can be individually replaced.

- If they are installed as part of a sub-assembly, then either the equipment to make those assemblies must be available or sufficient spares must be produced to meet expected breakage.

The repair procedure should consist of the following main steps:

- Preparations
  a. Preparation of replacement procedure & personnel training, including safety
  b. Preparation of mirror replacement parts – whether individual mirrors or sub-assemblies, including all fasteners required
  c. Preparation of tools, jigs and other equipment for the installation procedure

- Safe removal of broken mirrors, according to planned replacement locations

- Per heliostat:
  a. Disassembly of any mirror subassembly that has to be replaced, depending on heliostat design
  b. Installation of replacement parts
  c. QC check
  d. Update to Plant Maintenance System
3.4. Cleaning

A deep revision of the different cleaning methods of solar reflectors can be found in [1]. In general, the parameters of the selected cleaning method (pressure water, type of water, type of brushes, etc.) must be selected to prevent in the long term damages to reflecting surface (due to abrasion).

Water is the main cleaning agent used in conventional washing methods. It is either used alone by spraying high pressure water on the surface of soiled reflectors or in combination with a contact cleaning tool used for brushing, wiping or scrubbing the surface of soiled reflectors.

The non-contact cleaning consists in spraying high pressure water onto the dirty surface. According to [2-4], this method is quite effective in removing dust. However, it fails to completely remove all the dust cemented to the mirrors because of the resistance of dust particle to the action of water jetting. The cleaning effectiveness of this method is affected by parameters such as the distance between the high pressure nozzles and the cleaned surface, the nozzle characteristics and diameter, the angle of impingement and the applied jetting pressure. Although increasing the water pressure enhances the cleaning effectiveness [5], this solution is not advantageous because of its water consumption increase. Also, increasing water temperature is advantageous for the cleaning effectiveness [6].

Although high pressure water is effective in removing a great deal of deposited dust, it leaves some dust that builds up with repetitive cleaning cycles [3]. Contact cleaning consists either in brushing, wiping or scrubbing the soiled surface. This method is effective in removing full initial reflectance but special care must be taken in the selection of the type of the contact tool (mainly in hardness) to avoid surface abrasion. According to [2], using a soft wipe was successful in recovering full initial reflectance unlike non-contact cleaning methods. Despite its high cleaning effectiveness, contact cleaning can harm the surface of the reflectors by causing scratches or delamination over many cleaning cycles. As a result of applying different brush hardness and sand samples on polymer mirrors, it was recommended using a soft brush and water for benign cleaning [7]. A combination of scrubbing and rinsing is effective for highly adhered dust particles; however before applying any cleaning device, water spray should be first applied to remove loose dust [4].

Natural cleaning and detergents represent special cleaning mechanisms. The cleaning effectiveness of water-based washing methods can be enhanced using additives and detergents. Also, in natural cleaning, weather parameters such as winds and rainfall, can either reduce the cleaning frequency or, at the opposite way, aggravate the soiling of reflectors. Note that some detergent may corrode mirror edges and glass surface. Detergent with an appropriate pH has to be preferred (between 4-10). Anti-lime detergent is prohibited.

3.5. Heliostat cleaning

Perform an analysis of cleaning requirements and methods as part of the preparations for any new solar project. The following description relies upon BrightSource’s cleaning methods, and should serve as a guideline for this analysis. BrightSource works with a variety of cleaning methods, and selects the best option for each site depending on various site characteristics. These methods are:

- BrightSource Manual Cleaning Tools
- Manual Cleaning with Pressurized Water
- Solar Cleaner C4000 C-AP Mirror Washing Machine
- NT Mirror Washing Machine
3.5.1. BrightSource Manual Cleaning Tools

BrightSource has developed tools and a methodology for efficient manual mirror washing. This approach uses small amount of water for washing with high rate, and does not require pressurized water. The design of the manual tools is adapted to each heliostat model and to site conditions: details of the final design will be available during project execution. The equipment required is simple: a mobile water supply, portable small water supply and cleaning tool per worker.

Mirror Cleaning Rate

A team is composed of one technician / operator and a variable number of crews (typically 2-5), where each crew has two workers. A crew of two workers can clean 45 heliostats per hour for 10 hours net (out of 12 hours gross), or 450 heliostats a single work shift. The mirror washing process will be optimized during the O&M contract period to fit the site specific conditions.

Personnel Requirements

Each team will have:

- 4-10 unskilled workers, working as 2-5 crews
- One technician / operator

The entire mirror cleaning shift will have one foreman.

3.5.2. Manual Cleaning with Pressurized Water

The manual mirror washing method uses pressurized water and manual scrubbing, as shown in Figure 2.4 and Figure 2.5. The pressurized water is supplied from a vehicle with a water tank, pumps and hoses. The crews are supplied with elevated platforms for easy access to the entire mirror surface and use specialized wipers designed for maximum cleaning. The manual mirror cleaning consists of a team of nine workers, distributed as follows:

- Central utility vehicle / truck towing a trailer with a ~300 gal tank, pumps and four hoses on reels. The utility vehicle supplies the water to four crews. The utility vehicle will be operated by an operator.
- Manoeuvrable cleaning system consisting of elevated platforms mounted on top of a utility vehicle (ATV). One crew of workers is needed for each platform.
- Water hoses connect the platforms to the main vehicle.
Figure 2.4: Mirror Washing Route and Machines.

The washing procedure consists of the following stages:

- Deploy the main utility vehicle at the designated location.
- Rinse the mirrors with a pressure washer.
- Mop the mirror surfaces using the wipers.
- Rinse the mirrors a second time.
- Move to the next mirror location.

Figure 2.5: Mirror Washing in the Field.
Mirror Cleaning Rate
A team of nine workers can clean 40 heliostats per hour for ten hours net (out of 12 hours gross), or 400 heliostats a single work shift.

Personnel Requirements
Each team will have:
- Eight unskilled workers, working as four crews
- One technician / operator
The entire mirror cleaning crew will have one foreman.

3.5.3. Solar Cleaner C4000 C-AP Mirror Washing Machine
BP Metalameccnica (Italy) produces a cleaning machine Solar Cleaner C4000 C-AP, as shown in Figure 2.6, which has been adapted for use with heliostats. The machine aligns with a heliostat and wash its mirrors. This Mirror Washing Machine has been tested at BrightSource’s Ashalim solar field in Israel.

Mirror Cleaning Rate
The Mirror Washing Machine (see can clean 45 heliostats per hour for ten hours net (out of 12 hours gross), or 450 heliostats a single work shift.

Personnel Requirements
A single worker/driver is required for each machine.

3.5.4. NT Mirror Washing Machine
BrightSource developed semi-automated cleaning machine for its previous solar fields (see Figure 2.7). This machine has built-in cleaning mechanism. The machine aligns with the mirrors and then cleans.
**Mirror Cleaning Rate**

The NT MWM can clean 40 heliostats per hour for ten hours net (out of 12 hours gross), or 400 heliostats a single work shift.

### 3.5.5. Selecting the right Cleaning Plan

Mirror cleaning is required to maintain a high level of reflectance for the field as a whole. This depends on what the plant performance model assumes: for instance, an average cleanliness factor of 96%. In addition to routine cleaning, the case of dust storm has to be considered. In such cases, the entire solar field has to be cleaned as quickly as possible to an adequate level of reflectance (although it does not have to be restored immediately to the cleanliness factor of 96%). The water used is demin water. The water consumption needs to be an input to the plant water treatment system design. Cleaning can only be performed when the ambient temperature is above 0°C.

**Washing Cycles**

For this sample analysis, the number of cleaning cycles (i.e., number of times each heliostat is cleaned) was set to 7 per year. The number of cycles must be set to maintain the required average reflectance without adding significant equipment or personnel costs.

For the comparison below, cleaning was set at:

- Seven days a week
- One shift / day (during night)

**Table 2.2: Technical Comparison of Cleaning Methods.**
<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BrightSource Manual Cleaning Tools</td>
<td>1.5</td>
<td>0.02</td>
<td>450 / crew</td>
</tr>
<tr>
<td>Manual Cleaning with Pressurized Water</td>
<td>17.5</td>
<td>0.03</td>
<td>400 / team</td>
</tr>
<tr>
<td>Solar Cleaner C4000 C-AP Mirror Washing</td>
<td>12</td>
<td>0.12</td>
<td>450 / MWM</td>
</tr>
<tr>
<td>Machine</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NT Mirror Washing Machine</td>
<td>12</td>
<td>0.3</td>
<td>400 / MWM</td>
</tr>
</tbody>
</table>

**Comparison: Total Cost**

To determine the yearly cost for cleaning the solar field, the following information is needed:

- Capital costs for equipment
- Number of yearly washing cycles: how many times per year each heliostat needs to be washed depends on the soiling rate. Currently we assume that we need 6-10 washing cycles per year.
- Local water and fuel cost
- Labor cost

**Recommendation**

The following two options are an initial recommendation, for consideration by the O&M team. The two approaches allow a tradeoff between personnel and equipment costs.

- Combination of Solar Cleaner C4000 C-AP with BrightSource Manual Cleaning Tools, with a total of 10 workers as follows:
  - 1 Solar Cleaner - 1 worker
  - Manual: 1 team of 3 crews - 7 workers
  - One foreman and one technician

- BrightSource Manual Cleaning Tools, including one team of 9 workers and a foreman for a total of 10 workers.

Both options are sized according to 7 cleaning cycles per year. Alternative combinations of Solar Cleaner and manual crews can be devised, depending on the site O&M preferences. For instance, it may be wise to have two Solar Cleaner, to allow operation while one of the machines is undergoing maintenance. In addition, the total and relative numbers will likely be adjusted as the cleaning cycle requirement is refined through experience.

On-going expenses for the manual system are much lower, because it uses much less fuel and water. However, the Solar Cleaner can be used when the temperatures are very low (near 0°C) and manual cleaning is difficult.

The recommendation here selected the Solar Cleaner because it is a commercially available product. Alternative machines adapted for the particular site and heliostat design might be suitable.

The decision depends also on the number of dust storms expected per year. Cleaning after such dust storms is critical to restore sufficient reflectance for operation. It is not necessary to reach full nominal reflectance immediately. Therefore it is recommended to cope with the after-dust-storm cleaning by
using the BrightSource Manual Cleaning Tool, because it has a very high cleaning rate. It is easy to ramp up quickly for such scenarios: holding a small amount of extra equipment and hiring local workers on an as-needed basis.

The mirror washing process should be optimized by the O&M team based on experience of the site specific conditions.

**Using Snow & Rain to Clean Heliostats**

When significant rain is expected, position the heliostats at near horizontal position. This position allows the rain to run off, cleaning the mirrors naturally. It will also withstand all but the strongest wind conditions.

Snow can actually be used to clean the mirrors effectively. If snow is expected, position the heliostats at horizontal position. Make sure that the snow load is below the maximum allowed! Once the snow has built up, move the heliostats to vertical position. The snow will slide off and take much of the dust with it. Winds must also be taken into consideration before moving to vertical.

Both of these techniques can reduce the need for routine cleaning. For areas where a rainy season exists, consider no routine cleaning at all during that period.

### 3.6. Positioning

The elevation and azimuth angle of the heliostats during operation and over night depends on many factors. During day time operation, the heliostats track the sun at various angles depending on the time of year, time of day and their position relative to the central tower.

**Tracking** is a dynamic mode in which heliostats move according to the sun position and their own location in order to aim at a designated spot on the receiver. Calculations for this require precise information about the location of the heliostat and the tower as well as an almanac for the sun’s position and a precise clock to compare to the almanac. Different solar field suppliers may choose to implement this calculation in the central control system or disperse it to local controllers.

**Standby** is a dynamic mode in which the heliostats remain close to the desired tracking angle but without aiming at the receiver. Optimizing the use of Standby makes it much quicker to put heliostats into tracking (increased performance) and out of tracking (response to trip, reduced setpoints etc). The calculation methods are similar to those of tracking.

One issue that affects any heliostat movement is the possibility of contact with the ground, or in particularly dense areas of the layout, with other heliostats. Ground contact can occur if plants or rocks may move into the area around the base of the heliostat, for instance if the heliostats are not installed in pre-levelled ground or if the area is subject to heavy rain, and following growth of plants. The control system should provide feedback in case a particular heliostat experiences interference of that sort. The heliostat should stop moving and a notification should be provided so that the maintenance staff can investigate. Continued movement against such interference can cause damage to the motors and/or damage or even break the mirrors and support structures.

Additional factors that affect heliostat position during daytime operation include the need for maintenance personnel to enter the field as well as potential points of interference with the movement and positioning of the heliostats.
Operator commands may position heliostats at angles for convenient maintenance. See above for discussion of cleaning which is the main type of routine maintenance. For other maintenance purposes, the desired angle will depend on the heliostat design and on the specific maintenance activity.

It is good practice for the control system to “lock” heliostats into a maintenance mode, so that they do not respond to broadcast commands while so positioned. Depending on the power source, it may be possible to use a standard LOTO procedure, particularly if a large number of heliostats are affected. If not, then a virtual LOTO via the central control system is required.

While in such maintenance modes, the operators must monitor the field conditions in order to respond if wind or other emergency requires a change in position.

Depending on the field layout and spacing between heliostats, one very useful type of positioning is to open paths for access. These paths should be precalculated so that operators need only request a path from the control system. One method of creating a path is to align facing mirrors to create a corridor. This too is a maintenance position, with the same considerations as mentioned above.

While BrightSource heliostats are powered by photovoltaic cells, other solar fields may supply power to the heliostats over cables. In either case, it is desirable to reduce power usage for non-operational purposes.

One method of doing this is to implement an electronic hibernation mode, so that heliostat controllers reduce their overnight activity to minimum. If hibernation is used, the heliostats should be placed in a suitable position – either a safe position (see next section) or one that requires minimal movement between end of one day and beginning of the next. During such electronic hibernation, the local controllers must check periodically for messages, to allow response to potential emergency conditions, and to receive wake-up messages from the central control system.

To avoid overnight dust buildup, the heliostats may be left overnight in a vertical position (“Sleep”). This should not be used when problematic weather conditions are expected (see below).

### 3.7. Safety conditions

There are some special environmental events (high wind conditions, sand storms, hail storms, etc) that might severely damage the solar field. In this case, special instructions specified and implemented both at local controller level as well as overall solar field control must be followed, to protect the solar field and minimize the risk. Note that those instructions are very site specific, in order to plan for occasions of environmental condition changes. As example, in order for the heliostat to be at safe mode at certain max. wind speed (as well as gusts speeds), the time to attain the safe mode position should be accounted for and accordingly accounting for the local characteristics of high wind and prior wind speed steps before.

According to BSII recommendation, in case of high winds, heliostats should be placed in horizontal position (often called SAFE or STOW). At this angle they provide the least resistance to the wind. The exact wind speed at which the heliostats should move to SAFE depends on the heliostat design. The controller system should start the heliostats moving towards this angle before reaching the maximum design wind speed. Similarly, it should not send the heliostats out of this angle until the wind has dropped below a lower threshold. In the case of wind conditions overnight, there is no need to move them until it is time to start moving to morning operation positions. Heliostats can be left in this position for extended periods of time, such as in a plant maintenance outage. Additional wind protection can be provided by installing a wind fence around the solar field. Some suppliers design a heavier heliostat for installation.
around the perimeter. These can withstand higher winds than the rest of the heliostats, and they act as a wind break for the inner heliostats.

For the safety of people who are in solar plants with a heliostat field it is very important the definition of a “safety corridor” for the heliostats. Such a safety corridor is the path that the solar radiation reflected by each heliostat must follow to reach the receiver when the “track” command is received by the heliostat. The safety corridor must be clearly indicated to avoid the presence of people who could be affected by the concentrated solar radiation.

Finally, reflector resistance, according to glass thickness and glass composition, can be verified before exposure thanks to the norm IEC 61215 or UNE EN 12975.

### 3.8. Icing/dew/frost on Reflective Surface

The mirrors are much colder than the earth around them. For this reason, they will often be covered with dew in the morning, and with frost in colder weather.

There is no need to take any special actions to prevent dew. The dew will naturally evaporate in the morning after the sun rises. The speed at which it evaporates depends on the sun position and the heliostat location.

However, icing has a longer effect on operations. To minimize the risk of icing, the heliostats should not be positioned horizontally. Note that frost is typically not a problem when there are high winds, so the heliostats can be put in their safe position.

### 3.9. Ice Storms Impact on Heliostat Reflective Surface

See section above on Safety mode. Based on years of experience from the SEGS plants in the Mojave Desert and later heliostat projects in California and Israel, solar mirrors are highly resistant to damage to the surface caused by environmental conditions. Testing done with hail of various sizes on BrightSource heliostats showed no substantial damage. It is strongly recommended that you perform testing with the specific heliostat design and mirrors in order to determine what should be done in case of storms. Heliostats should likely be kept in vertical position during a hail storm, unless high winds are expected.

### 3.10. Preparing for a New Site

When preparing for a new site, the following recommendations will help in planning for maintenance.

#### 3.10.1. Soiling test

In order to determine how often cleaning will be required, the actual soiling rate on site is needed. Different soil and weather conditions result in very different dirt accumulation rates for different sites. Accumulation rates may vary at different times of year also.

The test should consist of a several mirrors positioned on or near the site. Regular reflectivity measurements should be taken from these mirrors. They should be cleaned periodically also. By tracking the cleaning versus the reflectivity measurements and taking into account weather conditions, it is possible to determine the best cleaning regime.

#### 3.10.2. Weather Conditions
A good understand of weather patterns will help in determining when wind protection is required. Acquiring online satellite data and providing this information in real time to the operators and/or the central control system is the best way to ensure early warning.

3.10.3. Hail Impact test

If the site experiences hail conditions, it may be helpful to perform a hail impact test. Standards for hail impact testing are available from IEC. Adjust the testing – hail size and speed -- according to the conditions likely to exist on the particular site.

3.11. Anti-soiling coatings

To minimize the effect of soiling in the field, the application of anti-soiling coatings on the surface of primary reflectors is an option discussed for several years already. So far anti-soiling coatings for primary reflectors of CSP plants have not reached commercial breakthrough even though they are commonly used for other kinds of applications (e.g. glazing products, bathroom surfaces) [8]. One CSP reflector manufacturer is known to have commercially offered products using anti-soiling coatings [9]. As there is no data from commercial plant operation, recommendations are not based on experience from plant operators, but from research campaigns in the field, including the ones conducted within the Raiselife project.

The advantages that anti-soiling coatings imply are mainly twofold:

- Anti-soiling effect: in the presence of particles, dust and dirt in the atmosphere, the ability of these to stick to the reflector surface are minimized. This way the mean soiling is decreased, increasing the mean reflectance of the solar reflectors. Depending on plant parameters and cleaning strategies, the cleaning frequency may be reduced.
- Easy-to-clean effect: when being cleaned, this process is more efficient, removing soiling to a greater extend resulting in a better recuperation of the initial reflectance.

There are three main effects are usually exploited to achieve the desired anti-soiling properties

- Hydrophilic coatings: usually silica based. This type of coatings forms a high surface energy surface leading to the formation of low contact angles between the coating and water droplets. Formation of very thin water films is provoked in the case of washing or rain and this way facilitating the removal of dirt.
- Hydrophobic coatings: Formulations of silica or titania nanoparticles are mainly used. The surfaces have a low surface energy and contact angles are high. This provokes the formation of small water droplets which easily roll over the surface taking present dirt particles with them.
- Titania based coatings also possess photocatalytic properties enhancing the decomposition of organic matter in the presence of UV radiation.

3.11.1. Recommendations for cleaning

Conventional silvered-glass mirrors have shown to be very resistant to environmental impact, both mechanical and chemical. Only on sites with the potential for strong surface erosion (high wind velocities, availability of airborne particles), mechanical damages lowering the specular reflectance of the reflectors were detected. The anti-soiling coatings on the other hand are usually additional layers on top of the
original surface. Depending on the type of coating, these often have a lower hardness and a functional structured surface. During O&M tasks it has to be avoided to alter the characteristics of the surface.

Generally, O&M should be the same as for uncoated primary reflectors. Cleaning techniques should be preferred that minimize damages to the surfaces. Some coatings have shown to possess a lower mechanical stability than bare glass surfaces of conventional reflectors. High pressure water cleaning should be preferred of mechanical cleaning brushes or similar equipment.

3.11.2. Spray coatings in the field

The option of anti-soiling coatings which can be applied in the field have been discussed as well. The advantage of this kind of coatings is that they can be reapplied in the field in the case of decreasing effectiveness of the coatings. Again degradation monitoring techniques should be applied to detect decreasing effectiveness of the coatings and to determine the frequency of re-application of the coatings.
4. Best practices on O&M of secondary reflectors in the solar field

In this section, the best practice on O&M of secondary reflectors in the solar field are explained. The goal is to provide plant operators with useful information and advises to be followed when applied the O&M tasks affecting the durability of secondary reflectors. In this case, it is important to highlight that the reflector material for secondary concentrators (based on silver reflective layer with a front top coating) is still a product under development.

4.1. Storing and handling prior to installation

Scratches, dirt and finger-contact should be avoided to the coated front surface of the secondary mirror panels. Power-free gloves should be worn during handling of the mirrors. Protective paper or cloth wrapping should be used to shield the coated surface during storage and transportation. The surface of the mirror should ideally be kept as flawless as possible to avoid localised corrosion points and maintain high reflectance. Coated mirror panels should be stored in a dry and clean environment.

4.2. Replacement and repair of components

When a receiver component (the receiver itself or a section of the secondary concentrator) is deteriorated or broken, the repair or replacement must be accomplished with extreme care to avoid any interference or damage of the secondary reflectors.

4.3. Cleaning

Cleaning after installation should use soft cloths and water jets. Scratching or abrasion of the coating should be avoided (e.g., the use of hard-bristled brushes). Finger contact, again, should be avoided and thus cleaning and all handling with gloves is essential.

During the operation of the plant, daily or weekly cleaning (with water jets and soft cloths) would be recommended. In this sense, the secondary reflectors should not be allowed to accumulate surface residues (dust / dead insect remains / bird faeces). This will allow localised absorption points which will cause localised temperature hot spots and increased corrosion.

4.4. Safety conditions

Localised hot-spotting caused by dangerous focusing strategies should be avoided to reduce the chances of high localised temperatures causing rapid degradation to the coatings reflectance and thus increasing absorption. With this respect, the secondary mirrors should not be exposed to temperatures above 450 °C, being the ideal operation temperatures below 350 °C. The mirrors should be installed with the correct cooling mechanisms (passive or active air) to ensure these conditions are not exceeded. The mirrors average reflectance should be monitored in field and a drop below 89 % reflectance should be noted and a panel exchange should be undertaken.
5. Best practices on O&M of receivers for solar towers in the solar field

In this section, the best practice on O&M of receivers in the solar field. The goal is to provide plant operators with useful information and advises to be followed when applied the O&M tasks affecting the durability of the receiver.

All tasks performed on tower require careful adherence to safety procedures as specified by each plant, with specific reference to working at height where applicable. In addition, procedures performed on the tower should not be performed when wind speeds exceed a safety level, typically 10 m/s. Follow manufacturer’s instructions for all tools and materials. All the information included in this section has been provided by BSII and is subject to confidentiality.

5.1. Coating Inspection

Coating inspection should be performed:
- Prior to commencement of on-tower touch up activity
- After on-tower recoating activity is complete
- Annually - for corrosion survey and solar properties monitoring

Reference Standard: SSPC-PA 2, Procedure for Determining Conformance to Dry Coating Thickness Requirements

During inspection the relative humidity shall not exceed 85%.

5.1.1. Materials, Tools & Equipment

The following table include a description of materials, tools and equipment.

<table>
<thead>
<tr>
<th>Table 2.3: Technical Comparison of Cleaning Methods.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Broom head</td>
</tr>
<tr>
<td>Lint free cloth</td>
</tr>
<tr>
<td>Spectrophotometer</td>
</tr>
<tr>
<td>Dry film thickness (DFT) gauge</td>
</tr>
<tr>
<td>Digital camera</td>
</tr>
</tbody>
</table>

5.1.2. Personnel Training

The following recommendations applied for the personnel training:
1. The inspection shall be performed by a trained and experienced inspector approved by relevant Product Engineering Representative.
2. The inspector must be trained and familiar with all the measurement equipment according to this procedure.
3. The inspector must be trained and familiar with all relevant safety equipment / PPE.

5.1.3. Inspection Method
For each panel, the inspection method consists of:
- Cleaning the area to be inspected
- Visual evaluation for coating uniformity, Measuring DFT and Absorptance
- Recording all data in the Panel Inspection Checklist or other inspection recording method approved by Company Home Office Representative

5.1.4. Cleaning Area Prior to Inspection

Cleaning must precede Dry Film Thickness (DFT) and absorptance measurements. Gently brush/clean off any dirt, sand and dust contamination from the area.

NOTE: Only a gentle brushing is permitted.

5.1.5. Dry Film Thickness Measurements

Dry film thickness (DFT) measurement shall be performed on the relevant area as follows:
- For an inspection area of up to one half of a panel, randomly chosen zones must be inspected. For each zone, measurements are required.
- For an inspection area of a half a panel and up to one complete panel, randomly chosen zones need to be inspected. For each zone, measurements are required.

5.1.6. Absorptance Measurements

If inspected area is a half of a panel or larger, absorptance measurement shall be performed on the relevant areas.

5.1.7. Visual Assessment of Surface Condition

Coating defects/imperfections (e.g., voids, scrapes, chips, or uncoated patches) on the panel surface must be identified and recorded.

5.1.8. QC Documentation Requirements

Provide the following documentation records
- Inspected panel identification according to plant identification method
- Solar absorptance measurements average and deviation or solar absorptance measurements range for each inspected panel. (report any abnormal measurement – location and value)
- DFT measurement average and deviation or DFT measurements range for each inspected panel. (report any abnormal measurement – location and value)
- Visual impression – defect, color change or other abnormalities description (Type and location) for each inspected panel.
- Photographs of damaged areas- general photos as well as close ups
- Summary and recommendations.

5.2. Coating Cleaning

The following specifies the procedure for on-tower panel cleaning.
5.2.1. Materials, Tools & Equipment

The following table include a description of materials, tools and equipment.

<table>
<thead>
<tr>
<th>Table 2.4: Technical Comparison of Cleaning Methods.</th>
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</thead>
<tbody>
<tr>
<td>Broom head</td>
</tr>
<tr>
<td>Lint free cloth</td>
</tr>
<tr>
<td>Digital camera</td>
</tr>
</tbody>
</table>

5.2.2. Cleaning Method

The goal is to remove any dirt, sand, dust contamination, or other residue from the entire panel.

5.2.3. For each panel

- In the Cleaning Report, record the panel identification data, date and time.
- Take a Before photo of the panel (or a representative part of it) and enter the photo ID in the Cleaning Record.
- Gently clean:
  a. Test the cleaning method on a small area to ensure it does not damage the coating.
  b. Clean only the entire irradiated area of the panel.
  c. If the area does not come clean, leave as-is, in order not to damage the coating.
- Take an after photo, preferably from the same angle as the before photo, and enter the photo ID in the Cleaning Report.

5.2.4. Coating Touch-up

The following are on-tower touch-up instructions. The procedure is performed on the tower without disassembling panels. The following BrightSource documents are used as references.

1. Coating Technical Data Sheet
2. Coating Safety Data Sheet
3. Application Specification
4. Solar curing protocol
5. Application specification

The following standards apply:
Table 2.5: List of standards.

<table>
<thead>
<tr>
<th>ID</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM D4417-93</td>
<td>Standard Test Methods for Field Measurement of Surface Profile of Blast Cleaned Steel</td>
</tr>
<tr>
<td>ASTM D7127</td>
<td>Standard Test Method for Measurement of Surface Roughness of Abrasive Blast Cleaned Metal Surfaces Using a Portable Stylus Instrument</td>
</tr>
<tr>
<td>SSPC-PA 1</td>
<td>Shop Field and Maintenance Painting of Steel</td>
</tr>
<tr>
<td>SSPC-SPI1</td>
<td>Power Tool Cleaning to Bare Metal</td>
</tr>
<tr>
<td>ASTM D4414-95</td>
<td>Standard Practice for Measurement of Wet Film Thickness by Notch Gages</td>
</tr>
</tbody>
</table>

**Environmental Conditions**

- Care shall be taken so that application area for recoating is clean: dry, free of dust, dirt, oils and any other contaminations, during the on-tower recoating / touchup activity.
- Work shall be performed under the best conditions achievable within scheduling constraints. Efforts shall be made to avoid above-normal wind, sand storm, rain or other environmental conditions that could adversely affect the coating.
  - a. Work shall not be performed for a period in which rain or above-normal winds are forecast
  - b. Painting primer or HSA coatings requires a two-day interval without rain (painting + drying) and hence shall not be performed if rain is forecast for the painting day or the day after.
  - c. Relative humidity (RH) shall not exceed 80%.
  - d. Ambient temperature shall be between 10°C and 35°C.
  - e. Maximum wind speed for painting application: 10 m/s

**Training & Approvals**

Prior to performing the recoating, the personnel shall be trained and qualified as follows:

- Relevant Product Engineering Representative shall train and instruct the painter and the Inspector per this Work Instruction.
- The main purpose of the training is for the painter to understand the procedure and practice execution before coating the actual panel.
- Prior to coating an actual SRSG panel, the painter shall practice on a "demo panel" (except curing step).
- The training shall include:
  - a) Surface preparation fine tuning
  - b) Paint and equipment preparation (mixing, assembling the spray equipment etc.)
  - c) Coating application per designated WFT and uniformity
  - d) Quality Inspections (profile depth, WFT, DFT (on coupons) etc.)

**Coating Materials**

The following are BrightSource recommended materials. Alternatives may apply.
Table 2.6: List of materials.

<table>
<thead>
<tr>
<th>#</th>
<th>Use</th>
<th>Material name</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Coating</td>
<td>◦ Coating system for T22 and T91 panels:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>◦ BSA-01 (primer) and BSA-22 (Top coat)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>◦ For In617 panels</td>
</tr>
<tr>
<td></td>
<td></td>
<td>◦ BSA-31</td>
</tr>
</tbody>
</table>

Team Roles & Responsibilities

Table 2.7: List of team roles and responsibilities.

<table>
<thead>
<tr>
<th>#</th>
<th>Position</th>
<th>Qualifications/Certification</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Workers/Painter</td>
<td>Trained and familiar with surface preparation and coating application.</td>
<td>Qualified by Product Engineering Representative.</td>
</tr>
<tr>
<td>3</td>
<td>Inspector</td>
<td>Trained and familiar with all the material, equipment and measurement devices according QC requirements, in order to prepare the surface and apply the paint according to this instruction</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Work manager</td>
<td>Trained and familiar with all the material, equipment and requirements in order to prepare the surface and apply the paint according to this instruction.</td>
<td></td>
</tr>
</tbody>
</table>

Touch-up procedure

The touch-up procedure depends on the type of metal.

Prerequisite

The following prerequisites apply when recoating work is planned:

- Solar field not aiming at the receiver working area.
- Receiver not operational (emergency shut down or other plant procedure) & in LOTO
- Wind speed do not exceed 10 m/s

Notes:

- The touchup procedure shall be executed on areas previously defined.
- The panel must not be touched with bare hands; gloves must be worn for all activities.
- In case the surface preparation stage takes more than 4 hours, the surface shall be re-cleaned before applying the primer layer.

Touch-up – Minor Touchup

It refers a situation in which the coating has been damaged and a minor touch-up is necessary. If the affected area is considered a minor touch-up, multiple areas on the same panel shall each be considered individually. Notes:

- For any unexpected findings, or deviations from expected results of actions, immediately notify your supervisor or the QA/QC representative.
• Care must be taken not to touch the panel with bare hands; therefore working with gloves is mandatory.

5.2.5. Coating - Solar Curing

Solar Curing is used when touch-ups to the coating have been performed with the panels in place. Curing requires that the receiver panels achieve a specific temperature profile, including temperature set points, ramp rates and curing durations. The On-Tower Curing procedure uses steam from the plant and solar field energy to heat the steam and reach the required conditions.

The method described below is specific to plant design, receiver design and materials and coating materials. It must be adapted to the specific nature of the receiver and coating as well as to the plant steam design.

*Evaporator Curing*

In the evaporator section, water in all the panels are flowing in parallel and mixing in the SRSG drum before circulating back into the panels via the SRSG circulating pumps.

*Superheater Curing*

The superheater is divided into two temperature regions, each with its own curing procedure: hot and cold regions.

5.2.6. Focussing Strategy & Coating Damage Prevention

Care taken during operation to avoid overheating the panels is critical to preventing damage.

*Monitoring*

The solar control system must constantly monitor the flows temperatures in the various areas of the panels in order to ensure that they remain within the specified limits and ROC conditions are observed. The flow must be sufficient to avoid hot spots without interfering with heat collection.

*Control*

The solar field control system must ensure that solar flux is aimed accurately and in the right amount in order to achieve the various temperature and flow setpoints. These process setpoints will change often during startup and then stabilize as steady state conditions are achieved. Maintaining this control is particularly difficult during periods of transient clouds.

The solar field control system will determine how to divide up available heliostat so that the flux is spread precisely across the various areas of the receiver surface. Accuracy of aiming is critical: when a heliostat is aimed at a specific location, the control system must know that it will actually hit that location within a known tolerance.
6. Best practices on O&M of metals and coatings for molten salts in the solar field

In this section, the best practice on O&M of metals and coatings for molten salts in the solar field. The goal is to provide plant operators with useful information and advises to be followed when applied the O&M tasks affecting the durability of the receiver.

6.1. Best practice on O&M of molten salts

Operation and maintenance (O&M) becomes an important concern with molten salt in the solar field. Currently the most common industrial compound is an alkali metal nitrate mixture composed of 60 wt.% NaNO$_3$/40 wt.% KNO$_3$ (commonly called Solar Salt). This mixture melts at 223 ºC and is thermally stable until about 530 ºC, offering high density, low vapour pressure, moderate specific heat, low chemical reactivity and low cost. Other important challenge of this commercial salt mixture is its high freezing point. All these properties are unique and need to be maintained throughout the life cycle of the CSP plant.

In addition, molten salt in general and nitrates in particular present impurities, such as carbonates, nitrites, chlorides, and sulphates, that not only induce even more corrosion, but also highly affect the thermal and physicochemical properties.

Other important aspect of molten salts is their degradation under operation. This degradation could be attributed both to reactions that lead to degasification processes and to variations in salt composition. In the case of Solar Salt, the decomposition of nitrate salts resulted in the formation of nitrite according to Reaction 2.1:

\[ \text{NO}_3^- \rightleftharpoons \text{NO}_2^- + \frac{1}{2} \text{O}_2 \quad (2.1) \]

On the basis of the foregoing, great care should be taken of the molten salt in the system and an O&M procedure should be considered on salt composition and properties for avoiding substantial reductions in salt quality, which would lead to important reductions in plant efficiency.

6.1.1. Periodic analyses of the salt

In order to monitor the composition and thermal properties of the salt, it is recommended to take samples from the salt mixture and carry out analyses on them. In this regard, melting, freezing and degradation temperatures should be determined in order to detect variations in the original values.

Additionally, impurity levels should be determined at each analysis. In this respect, it is recommended to at least analyse the concentration of chlorides and sulphates, which significantly affect the corrosive behaviour of the salts and their thermal properties. All this effects have been suitably analysed during the project, allowing fixing some operational limits.

Thus, after the experience gained during the project, the impurity level cannot exceed 700 ppm of Cl$^-$ and 700 ppm of SO$_4^{2-}$. Regarding the thermal properties, the degradation temperature cannot differ from the original value in more than 25 ºC, while the melting and freezing points should not increase more than 10 ºC.

The analyses of the salt should be carried out at twice a year, or at least once a year. If important changes are detected, operators should proceed with salt refilling until recovering the original parameters.
6.1.2. Corrosion monitoring system

The corrosion monitoring system proposed in the frame of RAISELIFE (Work Package 4) allows not only the evaluation of the corrosion mechanism that controls the corrosion process and estimate corrosion rates in contact with molten salts, but also the monitoring of the salt properties during plant operation.

Changes in salt properties can be evaluated from the value of the resistance of the electrolyte, which in this particular case is the molten salt. This value provides an insight into how the system evolves during the whole operation.

Therefore, an important O&M measure to be considered in plant is the installation of corrosion monitoring sensors in thermal storage tanks and molten salt pipes. These sensors will take measurements continuously during the whole life of the plant and will allow the operators to assess the degradation of the salts in real-time and evaluate the need of proceeding with salt analyses. This salt analysis should at least include the measure of the concentration of nitrates and nitrites, which as previously mentioned are the main species involved in the salt degradation.

Measurements should be taken at the very beginning of the plant operation, just after putting the salt into the tanks. The measured value will be used as reference during the plant life.

6.2. Best practice on O&M of metals and coatings for molten salts in the solar field

6.2.1. Slurry aluminium coatings

In the frame of RAISLEIFE, INTA has developed a promising coating for being used under molten salt environments. This coating is an aluminum slurry that can be applied on the substrate by spraying gun or using a brush, needing then a heat treatment at high temperature to obtain the desirable microstructure. Aiming at achieving a suitable adhesion of the coating, the alloy to be coated must be completely clean and have a good surface finish.

Once the coated materials are installed in the plant and are operational, it is recommended to perform a continuous monitoring of the corrosion into the coated pipes through which the molten salt circulates. If degradation of the coating/substrate is detected, it must be evaluated if this degradation influences the operation of the plant and if it requires a repair or maintenance in order prevent the material failure.

When a critical failure is detected in a coated pipe, through which the molten salt circulate, it is highly recommended to perform a replacement of the damaged pipe section. The reason for this recommendation is that an in-situ coating process is highly complex due to the small diameter of the molten salt pipes. On the other hand, if the failure is detected in the thermal storage tanks, after pumping off the molten salts, it should be assessed if the repair is viable for the re-commissioning of the tank. If this is the case, a superficial cleaning of the affected area should be carried out in order to remove both the salt and the damaged coating, as well as the oxides that could have been formed on the affected zone. Due to superficial cleaning efficiency, it is recommended to blast the surface to ensure a proper removal of the oxidation products, blow it with compressed air and finally clean it using alcohol to eliminate traces that could remain on the surface. Once the affected area has been prepared, the new coating can be applied and heat treated using, for example, a blowtorch. After that, the possible remains of undiffused slurry should be eliminated. Once performed this repair procedure, operation in plant could continue.

6.2.2. Cr-diffusion coatings
Within the scope of RAISELIFE, DFI has developed a Cr-diffusion coating, which can be applied on components via the industrially well-established method of pack cementation. The so-called DFI-coating aims at an enhancement of the Cr-reservoir of ferritic-martensitic steels which can be employed as structural materials in the receiver tubes which would lead to a significant increase in the cost-efficiency of CSP plants. The manufacturing process does not require line of sight and thus can be easily applicable to complex geometries. A surface pre-treatment e.g. grid blasting is strongly recommended to remove the native oxides from the surface of the alloy. The pack mixture contains the masteralloy (Cr), a halide activator (e.g. NH$_4$Cl) and inert filler (Al$_2$O$_3$) in a defined weight ratio. It should be noted that halide activators can be hygroscopic, thus it is advised to store the activator powders in desiccator. The samples are embedded in the pack mixture in alumina retorts and heated up to the coating manufacturing temperature (around 1000°C) under a flowing (4 l/h) reducing atmosphere (Ar + 5 vol.% H$_2$). The coating process is based on transport of chromium onto the alloy surface via gaseous species followed by the solid-state diffusion of Cr into the alloy. The temperature is kept constant for a certain dwell time which is decisive for the desired coating thickness and microstructure alongside the temperature. Subsequently, the samples are cooled down to ambient and removed out of the retorts and cleaned in ultrasonic ethanol bath. The residual pack powder should be stored carefully and handled as chemical waste since it contains metal cations and halides.

Similar to the slurry aluminide coating developed by INTA, corrosion monitoring of DFI-coated samples is strongly recommended. This enables the detection of degradation processes of the coating. For instance, mechanical failure of the coating e.g. formation of cracks, increases Cr-depletion significantly, since the cracks formed are re-healed with Cr-rich oxides. This in turn decreases the chemical lifetime of the coating. Hence mechanical and chemical degradation processes of such coatings interact with each other under service conditions and isolating the nature of failure can be very difficult. Corrosion monitoring is regarded is a very useful tool to assess the degradation and the component can be replaced or strip/recoat measures can be conducted. Strip/recoat process is an industrially well-established method in the turbine industry and includes removeing the damaged coating via chemical etching and then the blank surface of the alloy can be recoated again.
7. References


Chapter 3: D6.6 Best practice on Economic Assessment of Material Degradation

1. Scope and objective

To increase the power output of solar thermal power plants over the full life time, it is essential to focus on the improvement of functional materials such as mirror coatings, selective and non-selective receiver coatings, as well as corrosion-resistant steel and coatings to use with molten salt. The EU-funded project RAISELIFE focuses on raising the lifetime of these key functional materials. Materials are being developed and tested with accelerated aging tests to obtain information about degradation mechanisms and property degradation over lifetime. System simulations are used to quantify the impact of the results on the plant performance by calculating the electricity yield. This yield is included in the economic assessment. While both the project RAISELIFE and this guideline focus on the assessment of functional coatings, most of the suggested best practises can equally be applied to other aspects of the power plant system.

This guideline describes the steps of techno-economically assessing the impact of degradation of these new material developments in solar tower plants:

1. Implementation of degradation curves that were derived from accelerated aging and on-site tests into system simulation software. While it is usually sufficient to perform annual simulations to obtain the electrical yield of solar thermal power plants, multi-year simulations are required when considering degradation mechanisms to take into account the change of optical and thermal parameters as well as component replacements or re-coatings over the full lifetime of the plants.

2. Comparison of different coating developments by virtually applying them on predefined reference power plant models. Lifetime system simulations are performed to obtain the electricity yield over the full lifetime of a plant, while taking into consideration degradation mechanisms.

Techno-economically Assessment of solar thermal power plants by relating the discounted investment and maintenance costs to the simulated electricity yield. Levelized Cost of Electricity (LCOE) or Levelized Cost of Coating (LCOC) are calculated and enable a fair comparison between different coating developments.
2. **Normative references**

3. Terms and definitions

Table 3.1. Terms and definitions

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRS</td>
<td>Central Receiver Systems</td>
</tr>
<tr>
<td>CSP</td>
<td>Concentrating Solar Power</td>
</tr>
<tr>
<td>FEM</td>
<td>Finite Element Method</td>
</tr>
<tr>
<td>HTF</td>
<td>Heat Transfer Fluid</td>
</tr>
<tr>
<td>LCOC</td>
<td>Levelized Cost of Coating</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Electricity</td>
</tr>
</tbody>
</table>
4. Modelling of degradation mechanisms

Key functional components of CSP plants like coatings have different characteristics and performance indicators. While for mirror coatings, high reflectance is the most important parameter, coatings for absorber tubes should have high absorptance and preferably low emittance. The storage and piping system needs to withstand the harsh conditions of high temperature and be resistant to corrosion in contact with molten salt, so corrosion resistant coatings can be used. All these materials should at the same time be as inexpensive as possible in order to reach a low LCOE for the solar thermal power plant.

The procedure of degradation modelling for primary mirror coatings and absorber coatings is described in the following RAISELIFE guidelines:

5. Modelling of degradation impact on plant performance

In the following sections, the suggested procedure for modeling the lifetime performance of the functional materials and its impact on plant electricity yield.

5.1. System modeling and simulation

For the calculation of the impact of degradation effects, the used simulation tools need to fulfill certain criteria. For example, they need to be able to simulate multiple years in a row. Only then, the decline of material parameters can be assessed over the full lifetime of a plant. The usage of thermo-hydraulic simulation software is recommended to include transient effects in the simulation and increase the accuracy. The main functionality needed in simulation software to evaluate the impact of degradation on electricity yield is summarized in the table below.

Table 3.2: Main functionality needed for dynamic system simulation to evaluate the impact of degradation on electricity yield

<table>
<thead>
<tr>
<th>Functionality</th>
<th>Effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>Degradation of key functional materials (heliostats and receiver)</td>
<td>Avoid overvaluation of energy yield</td>
</tr>
<tr>
<td>Multi-year-simulation</td>
<td>Consider degradation in subsequent years of plant lifetime</td>
</tr>
<tr>
<td>Downtime due to maintenance</td>
<td>Consider electricity losses due to shutdown of plant</td>
</tr>
<tr>
<td>Consideration of mass flow and capacity within components</td>
<td>Consider transient effects</td>
</tr>
<tr>
<td>Thermal receiver efficiency calculation depending on thermal load on receiver</td>
<td>Consider part-load behavior</td>
</tr>
<tr>
<td>Power block efficiency calculation on thermal load to power block</td>
<td>Consider part-load behavior</td>
</tr>
<tr>
<td>Defocusing of heliostats to avoid exceeding of maximum receiver thermal load</td>
<td>Avoid overvaluation of energy yield</td>
</tr>
<tr>
<td>Consideration of minimum thermal yield in receiver</td>
<td>Avoid undervaluation or overvaluation of energy yield</td>
</tr>
</tbody>
</table>

As this guideline focuses on coatings, a higher level of detail is required with respect to the simulation models of heliostat field and receiver – the components where the coatings are used. Thus, a detailed ray tracing model for the heliostat field / receiver interaction and a detailed thermo-hydraulic receiver model are suggested, while the other components are covered in a simplified manner in the overall system simulation.

5.1.1. Optical simulation of heliostat field / receiver interaction

Ray tracing software calculates the flux distribution on absorber surfaces with high spatial resolution. Reflections from the receiver tubes towards the environment or to other tubes should be considered as well as all relevant optical effects like cosine losses, shading, absorption on heliostats, blocking, spillage, atmospheric attenuation and reflection on the receiver surfaces. One way to couple the raytracing results with other simulation tools is to use a sky discretization approach [1, 2] to calculate the transient distribution of concentrated radiation on the receiver surfaces in the form of flux maps depending on sun position and receiver load. These act as an input to the thermal receiver model and system simulation.
5.1.2. Thermal receiver model

One way to model the thermal efficiency of the receiver is to use detailed FEM simulation. The previously described flux maps can be input to this FEM model, defining the radiation boundary conditions. For absorber tubes, insulation and heat transfer fluid, the local temperatures are obtained. Based on these temperatures, the thermal receiver efficiency is calculated with the thermal losses by long-wave radiation, convection and conduction. The thermal efficiency depending on different load cases and is input to the system simulation.

5.1.3. Dynamic system simulation

A transient system simulation tool should be used that is optimized for solar thermal power plants applications. All relevant components of the reference system like heliostat field and receiver, HTF pump, thermal energy storage and power block need to be included. Transient effects and operational constraints like mass flow and temperature limitations should be considered to enable the simulation of solar field and power block start-up and shut-down as well as heliostat defocusing. Degradation mechanisms of functional material parameters as well as downtime due to maintenance or replacement of components need to be implemented. To evaluate the system behaviour including degradation over the full life time of a plant, multi-year simulations need to be performed. The energy output of these multi-year simulations can be used to perform feasibility studies and assess the system design and performance.

5.2. Integration of degradation models in system model

In section 4 (Modelling of degradation mechanisms) outlines the derivation of degradation models from measurement data. In the case of heliostat coatings, these are models describing the change of reflectance over time and in the case of absorber coatings the change of absorptance and emittance over time. The following paragraph describes the implementation of these models in the system model.

If degradation is considered, the potential solar radiation gain of the receiver $\dot{Q}_{\text{abs, pot}}$ is calculated according to equation (3.1). The effective solar absorptance is a function of time. Therefore, degradation mechanisms of the receiver can be taken into account. The weather data input file provides the corresponding Direct Normal Irradiation (DNI). The concentration factor is a result of prior or simultaneous ray tracing simulations and depends on the current sun position (solar zenith and azimuth angles), on the heliostat field and receiver characteristics and design, as well as on aiming strategy. Technically, also the degradation of the heliostat reflectance should be considered in the ray tracing simulations, as it affects the concentration factor. However, this would increase the number of simulation cases, as time would be an additional degree of freedom. At the same time, ray tracing is computationally very expensive. As an alternative without much loss of accuracy, the concentration factor is multiplied by the fraction of current heliostat reflectance and the reference reflectance that was used to calculate the concentration factor in the ray tracing simulations, reducing the computational cost is significantly.

The ray tracing simulation can be performed once in the beginning of each system simulation. A lookup table with concentration factors of the irradiation from the heliostat field on the receiver depending on various sun positions can be derived, by interpolating with a radial basis function network in a grid which covers the relevant part of the sky [1, 2]. The system model later extracts the corresponding concentration factor in each time step from the lookup table.
\[ \dot{Q}_{abs,\text{pot}} = \alpha_{\text{rec,eff}}(t) \cdot DNI \cdot A_{\text{rec}} \cdot \frac{C}{\rho_{\text{helio,stat,ref}}} \cdot \rho_{\text{helio,stat}}(t) \] (3.1)

Where:

\( \alpha_{\text{rec,eff}} \) is the effective solar absorptance,
\( t \) is the time,
\( DNI \) is the Direct Normal irradiation,
\( A_{\text{rec}} \) is the projected receiver area,
\( C \) is the concentration factor,
\( \rho_{\text{helio,stat}} \) is the reflectance of the heliostats,
\( \rho_{\text{helio,stat,ref}} \) is the reference reflectance used in raytracing simulations.

The effective solar absorptance \( \alpha_{\text{rec,eff}} \) is calculated with the following equation [3]:

\[ \alpha_{\text{rec,eff}}(t) = \frac{\alpha_{\text{rec}}(t)}{\alpha_{\text{rec}}(t) + (1 - \alpha_{\text{rec}}(t)) \cdot \frac{A_{\text{rec}}}{A_{\text{surface}}}} \] (3.2)

Where:

\( \alpha_{\text{rec}}(t) \) is the solar absorptance of the receiver coating,
\( A_{\text{surface}} \) is the surface area of the receiver.

The potential solar radiation gain \( \dot{Q}_{\text{gain,\text{pot}}} \) is calculated according to the following formula. The thermal losses \( \dot{Q}_{\text{loss,th}} \) that are a function of emittance \( \epsilon_{\text{rec}} \), wind speed \( v_{\text{wind}} \) and time (to consider degradation effects) is subtracted from the potential solar radiation gain.

\[ \dot{Q}_{\text{gain,\text{pot}}} = \dot{Q}_{abs,\text{pot}} - \dot{Q}_{\text{loss,th}}(\epsilon_{\text{rec}}, v_{\text{wind}}, t) \] (3.3)

Ultimately, the potential thermal gain is capped, if the maximum outlet temperature \( T_{\text{out,max}} \) – resulting from the potential thermal gain – is exceeded. This will emulate the real behavior of the plant controller that defocusses some heliostats, if the receiver flux is too high. Therefore, the difference between this capped thermal gain and the potential gain is the defocusing losses \( \dot{Q}_{\text{defocus}} \):

\[ \dot{Q}_{\text{gain}} = \dot{Q}_{\text{gain,\text{pot}}} - \dot{Q}_{\text{defocus}} \] (3.4)

This way, also for the consideration of heliostat defocusing, no additional ray tracing simulations are required.

### 5.3. Selection of reference plant(s)

In order to evaluate different material developments and their impact on plant performance, they need to be compared under the same conditions. Therefore, a reference power plant needs to be defined, including plant dimensions and system specifications. For CRS systems, this includes:

- site specifications and weather data
- heliostat dimensions, reflectance, field layout and aiming point strategy
- receiver dimensions, setup, material, absorptance, emittance, operational parameters like maximum receiver film temperature and temperature set point
- storage dimensions and characteristics
- power block size and characteristics
- back-up boiler characteristics
- HTF properties
- operation strategy

The specific parameters depend on the system model layout as well as the evaluated material developments.

### 5.4. Selection of simulation scenarios

As a base case/scenario, degradation of functional materials is deactivated.

For the comparison of the different functional materials, each material in the plant is evaluated separately by virtually “replacing” one component in the plant at a time. For the evaluation of heliostat coating impact for example, the reference reflectance is replaced with the (initial) reflectance of the new material. Additionally, the degradation model is applied, which causes the reflectance to drop throughout the lifetime of the plant. At the same time, no degradation is considered in the other components like the receiver. An equivalent procedure is applied for all plant aspects to be evaluated. This way, the effects of the different material degradation mechanisms are assessed each in a separate scenario. The energy yield obtained by using the new developed materials will be compared with each other and to the base case.

At the same time, maintenance strategies that are linked to the material developments can be applied and used for the evaluation. For example, not only degradation, but also re-coating intervals of absorber coatings can be included in the model. This means that – in a predefined time interval – the absorber model is “re-coated” by resetting the absorptance and emittance to their initial value, while applying a maintenance downtime of hours, days or weeks.

### 5.5. Scaling of system design

Each material will be simulated in a predefined reference system. However, depending on the evaluated material, the plant design may have had been different during the initial design process. For example, if a newly developed absorber coating shows an absorptance that is 2 % higher than the absorptance of the reference absorber coating, the heliostat field could have been 2 % smaller, while still generating the same thermal power that is transferred to the heat transfer fluid. Ignoring this, the impact of the new (improved) coating would be underestimated, as – especially in the middle of the day – the receiver would not be able to process the additional thermal power and defocusing losses would be increased. This is why the reference system design should be corrected according to the characteristics of the new material development. The advantage of improved coatings then lies is the cost reduction due to the reduction in heliostat field size.

In the case of mirror coatings, the scaling factor \( f_{\text{heliostat}} \) is applied depending on the reflectance of the new material \( \rho_{\text{heliostat}} \) and the reference reflectance \( \rho_{\text{heliostat,ref}} \).

\[
f_{\text{heliostat}} = \frac{\rho_{\text{heliostat}}}{\rho_{\text{heliostat,ref}}}\quad (3.5)
\]
The scaling factor is then used to calculate the heliostat field size $A_{hsf}$ by scaling the reference heliostat field size $A_{hsf,ref}$.

$$A_{hsf} = f_{helio} \cdot A_{hsf,ref}$$  \hspace{1cm} (3.6)

Similarly, in the case of absorber coatings the scaling factor $f_{rec}$ is applied depending on the absorptance of the new material $\alpha_{rec}$ and the reference absorptance $\alpha_{rec,ref}$. The effect of change in emittance is neglected for calculating the plant design scaling factor.

$$f_{rec} = \frac{\alpha_{rec}}{\alpha_{rec,ref}}$$  \hspace{1cm} (3.7)

The scaling factor is again used to calculate the heliostat field size $A_{hsf}$ by scaling the reference heliostat field size $A_{hsf,ref}$.

$$A_{hsf} = f_{rec} \cdot A_{hsf,ref}$$  \hspace{1cm} (3.8)

Later, the corrected aperture area is applied not only in the technical system simulation, but also in the economic analysis and calculation of investment costs.

The new heliostat field design would ideally require new raytracing simulations. However, the variation of the heliostat field size is in a range that a linear relationship between change of heliostat field size and change of flux concentration on the receiver can be assumed. Therefore, the raytracing results (concentration factor depending on sun position) are scaled linearly according to the scaling factor.

In conclusion, the application of scaling factors improves the fair comparison of different material developments. Materials with better optical efficiencies do not lead to higher thermal yields, as this would also raise defocusing losses and therefore be disadvantageous for the material assessment. Instead, the heliostat field area is reduced to keep the thermal yield at a constant level, leading to lower system costs and therefore a reduction in LCOE.
6. Techno-economic assessment

The economic evaluation of material developments is an important aspect of the RAISELIFE project. The economic impact of each material development is assessed. For each simulation scenario, the energy yield in each year of the plants lifetime is obtained. This energy yield is input to the calculation of the economic key performance indicator Levelized Cost of Electricity (LCOE).

Apart from the material costs, the parameters for cost assessment will be the same for all evaluations of one reference plant. This includes the life time of the plants, investment costs for all components apart from the evaluated material, operation and maintenance costs as well as interest rate. For a clearer distinction between general operation and maintenance costs and replacement and re-coating costs, replacement and re-coating costs are listed as separate parameters. This way, the price of replacing and re-coating components can be evaluated more clearly, as this is particularly relevant for the evaluation of function material performance.

6.1. Cost figures and models

6.1.1. LCOE

To evaluate the simulation results, the Levelized Cost of Electricity LCOE is calculated based on the equation below [4].

\[
LCOE = \frac{C_{\text{capex}} + \sum_{t=1}^{T} \frac{C_{\text{opex},t} + C_{\text{replex},t}}{(1+i)^t}}{\sum_{t=1}^{T} \frac{E_{el,t}}{(1+i)^t}}
\]  

(3.9)

With:

- \(C_{\text{capex}}\) Total investment costs
- \(T\) Lifetime of plant
- \(t\) Year of plant operation
- \(C_{\text{opex},t}\) Operation & maintenance costs
- \(C_{\text{replex},t}\) Replacement and re-coating costs
- \(E_{el,t}\) Electricity yield
- \(i\) Interest rate

6.1.2. LCOC

Another method to compare different absorber coating developments with each other was introduced by Ho [5]. The Levelized Cost of Coating (LCOC) is calculated according to:

\[
LCOC = \frac{\sum_{t=1}^{T} C_{\text{coating}}}{\sum_{t=1}^{T} E_{th,t}}
\]  

(3.10)

With:

- \(C_{\text{coating}}\) Initial coating costs, re-coating costs as well as costs of additional or fewer heliostats due to system design scaling
- \(T\) Lifetime of plant
- \(t\) Year of plant operation
\[ E_{\text{th},t} \]  
Thermal energy yield absorbed

This method can also be applied to the evaluation of heliostat coatings (protective or anti-soiling).

### 6.2. Cost data

For the calculation of LCOE, investment and maintenance cost data is needed for the reference plant and components, as well as for the functional material evaluation. A detailed breakdown of costs data is only necessary for the parts that are evaluated. In the case of evaluation of absorber coatings, no detailed information on heliostat field cost breakdown is of advantage. Just the breakdown of receiver costs, coating costs and re-coating/maintenance cost is required to consider differing costs for the evaluated materials.

The advantage of the LCOC evaluation is that not even overall plant costs are needed, but only the cost of the coating, re-coating costs and the costs of additional or fewer heliostats due to system design scaling.
7. Application

7.1. Assessment of long-term coating performance

In the project RAISELIFE various functional materials, such as heliostat protective as well as anti-soiling coatings, absorber coatings as well as corrosion resistant steel coatings were developed. Slight differences in the method to assess each of these materials are described below.

7.1.1. Heliostat protective coatings

The main material property of protective coatings that affects the energy yield of a solar thermal power plant is the reflectance. Therefore, the reflectance drop over time can be considered. Updated costs of new coating developments can be taken into account. Replacements that are necessary due to the breakage of mirrors along the lifetime of the plant could be considered in the cost analysis. Replacing mirrors due to low reflectance is not common in commercial plant operation, as the degradation of the reflectance is comparatively small.

7.1.2. Heliostat anti-soiling coatings

Due to soiling, the reflectivity of heliostat mirrors is further reduced. Anti-soiling coatings reduce the adhesion of soil on the mirror surface. The reflectivity drop due to varying soiling rates can be considered in the simulations. Also additional costs for these additional anti-soiling coatings should be included in the cost calculation.

7.1.3. Absorber coatings

The main material properties of absorber coatings that affect the energy yield of a solar thermal power plant are solar absorptance and thermal emittance. Therefore, the absorptance and emittance drop over time should be considered when evaluating the impact of absorber coatings. In addition, in commercial CRS power plants it is common to re-coat the receiver panels every few years to increase the absorptance and reduce the emittance of the surface. However, the re-coating process is quite complex, especially if the coating needs to be applied on the ground and the receiver needs to be disassembled. The costs for this process, as well as the associated downtime of the plant need to be taken into consideration. If this data is available, the ideal re-coating interval can be identified for each coating in order to reach the lowest LCOE/LCOC.

7.1.4. Corrosion-resistant steel coatings

Corrosion resistant coating can be used in a molten salt solar thermal power plant to use cheaper substrate steel e.g. in storage tanks. Coatings protect steel from corroding. These coatings have negligibly small effect on the system performance. Therefore, the corrosion-resistant coatings do not need be part of the technical evaluation. However, the system costs can be reduced by using cheaper steels in some components like the storage tanks. This cost reduction reduces the LCOE and can be evaluated.

7.2. Exemplary case studies

The herein described tool chain – as developed in the project RAISELIFE – enables the assessment of operation strategies, like the impact of re-coating intervals on the plant’s economic profitability. This tool
chain consists of the Fraunhofer ISE raytracing software Raytrace3D [6], the DLR thermal efficiency FEM model ASTRID [7] and the Fraunhofer ISE dynamic system simulation tool ColSim CSP [8].

For the purpose of assessing the developed materials, a reference CRS power plant was selected. This plant is located in Ouarzazate, Morocco and has a gross electricity output of 150 MW, a thermal power of 600 MW and about 4.5 hours of storage. The system layout is shown in Figure 3.8. The heliostat field consists of 72,000 heliostats of 20.8 m².

![Figure 3.8: System layout of the RAISELIFE CRS reference plant](image)

Various assessments were performed in the project RAISELIFE. One was the optimization of the re-coating interval in order to find the minimum LCOE. The degradation curve as well as costs and related downtime of each re-coating process vary depending on the coating; these optima are different in each case. The figure below shows electricity yield and related LCOE for life time simulations with varying re-coating intervals. As shown, the minimum LCOE is not reached for the re-coating interval resulting in maximum electricity yield. Instead, the minimum LCOE in this case is reached for a re-coating interval of 15 years. This corresponds to one re-application during the lifetime of 30 years.
The tool chain also enabled the comparison of plants with a combination of different coatings (heliostat protective and anti-soiling coating as well as absorber coating). Figure 3.10.3 shows the electricity yield in each operation year for two cases. It shows that already from year one the yield is higher for case 1, mainly because of an improved anti-soiling coating that leads to higher average reflectivity. In case 2 the decline of electricity yield is stronger due to degradation which is why the receiver needs to be recoated more often, whereas the case 1 receiver is only recoated once. This can be seen from the sudden drop in electricity yield (due to the downtime of the system during the recoating process) and then an increased electricity yield in the subsequent years.

Another assessment was focusing on the impact of anti-soiling coatings. Anti-soiling coatings reduce the adhesion of soil on the mirror surface. A cleaning interval of fourteen days was assumed for all evaluations. The figure below shows the reflectivity drops that were used while different anti-soiling
coatings are applied. The uncoated mirror case acts as reference condition. As shown in the figure below, all presented coatings lead to significantly lower LCOEs than the uncoated mirror. Coating 2 leads to the lowest LCOE, with a reduction of 1.52 % as compared to the base case. However, no additional costs were assumed for anti-soiling coatings of this study.

![Figure 3.11: LCOE and electricity yield for reference case and different anti-soiling coatings](image-url)

*Figure 3.11: LCOE and electricity yield for reference case and different anti-soiling coatings*
8. References


Chapter 4: D6.7 Best practice on Accelerated Aging Testing

1. Scope and objective

This project focuses on raising the lifetime of five key functional materials for concentrated solar power (CSP) technologies:

- Protective and anti-soiling coatings for primary reflectors;
- Very high-reflective surfaces for heliostats;
- High-temperature secondary reflectors;
- Receiver coatings;
- Corrosion resistant high temperature metals and coatings for molten salts.

For this purpose, the project brings together a broad consortium formed of leading industry partners, SMEs and research institutes of the concentrated solar thermal and material science sector. The project scope has been significantly shaped by the leading Engineering, Procurement and Construction (EPC) of ST technology BSII. This unique constellation permits a direct transfer of the obtained results in RAISELIFE into new commercial CSP plants within less than 5 years.

The gained experience on accelerated testing methodologies, degradation monitoring and measurement techniques as well as sample treatment and correlation to in-service results will be summarized in a catalogue of good practices. This catalogue of good practices will be developed by the partners to reduce in-service degradation and will be made available to the CSP community by transferring it to national and international standardization committees and feeding the results into working groups like SolarPaces Task III.

This catalogue will make use of the results of WP 1 to 5 and will include a compilation of good practices on: (a) the detection and monitoring of degradation during service and operation in the field as well as after accelerated testing, derived from agreements reached between all testing institutions/partners, (b) application, operation and maintenance of functional materials and coatings, e.g. information on cleaning, collected and derived from recommendations of coating and operating partners, (c) economic impacts and economic viability of different measures influencing the in-service degradation, which will make use of both practical experiences of industrial partners and results from the economic assessments of T5.3, (d) testing protocols and accelerated aging procedures to reproduce outdoor effects, derived from the knowledge and results of the partners performing accelerated aging tests, (e) good practices and a protocol for evaluating corrosion in molten salt environments will be developed in the frame of WP4, (f) good practice on steel selection for CSP (VAL).

In particular, this deliverable is devoted to the best practice on accelerated aging of functional materials in the solar field. That includes all issues related with accelerated aging and testing protocols. General recommendations are given and minimum requirements are presented to produce useful, meaningful and repeatable results for the tasks of lifetime prediction, quality control and comparative studies on different materials.
2. **Normative references**

- IEC 62108 2016. Concentrator photovoltaic (CPV) modules and assemblies - Design qualification and type approval.
- MIL-STD 810 G 2014. Environmental engineering considerations and laboratory tests
3. **General aspects of accelerated aging tests (DLR, CIEMAT, MASCIR, Fraunhofer, BSII, AGC, UCM, DFI, INTA, PROMES, VAL)**

In this section, aspects are addressed that apply for all material classes mentioned in the document. The task is to provide all parties which conduct any form of accelerated aging tests with useful information on key aspects to keep in mind and parameters to be fulfilled.

### 3.1. Scope and Objective

The first step in developing an accelerated testing campaign has to be the definition of its objectives. The selection of all important parameters depends on the goal of the campaign and an early determination of these facilitates the planning and avoids unnecessary changes in the course of the campaign.

The main reasons accelerated campaigns are conducted include the following:

- **Manufacturing/process control:** Manufacturers of materials and components need a way to assure the quality of their product. The sooner an evaluation of produced material takes place, the sooner a reaction to possible problems can be taken. Depending on the type of product, an evaluation of all or only a selection of the manufactured goods can be undertaken.

- **Comparative testing:** Direct comparison of different materials of similar properties, usually with the same purpose may be interesting in different cases. Among those cases are, for manufacturers to compare the quality of competitor’s materials, for project developers the selection of material which is available from different manufacturers and research purposes.

- **Lifetime prediction:** Results of the tests give an estimation of the expected lifetime of the material under certain in-service conditions. The development of such test programs is complex and usually based on correlations determined between long-term outdoor exposure results and extensive accelerated testing campaigns.

### 3.2. Samples

Adequate selection of samples is crucial to gain meaningful results. Parameters as type, number, size, selection and treatment of samples have to be carefully selected and reported.

### 3.3. Parameters

Parameters of the tests have to be selected carefully. Realistic in-service conditions should be known and based on that, parameters should be selected, accelerating degradation but not causing unrealistic degradation, which would not happen in the field. Usually, one or several stress parameters (e.g. temperature, humidity, radiation) are applied. A combination of several tests may be necessary to cover all important stresses.

Measurement parameters should be significant and adequate to describe sample’s quality and allow the analysis of possible degradation taking place.
3.4. Reporting

All important parameters for testing have to be reported together with the results. Incomplete data can decrease the value of the experiments. Especially when analysed by third parties after testing, this is of utmost importance.
4. **Best practices accelerated aging of primary reflectors (DLR, CIEMAT, Fraunhofer, Mascir, BSII, AGC)**

In this section, the best practices on accelerated aging of primary reflectors are summarized. The goal is to provide all parties, which conduct any form of accelerated aging tests, with useful information on key aspects to keep in mind and parameters to be fulfilled.

This chapter includes specific subsections for:

- The testing of anti-soiling coatings;
- Particle erosion testing of primary reflectors.

### 4.1. Sample selection

Usually at least 3 samples per material and test should be used to have a minimum statistical validity. A size of around 10x10 cm² has been found to be appropriate to facilitate several measurements on the sample surface and to present a surface big enough to appreciate degradation. Samples should come from running production and be selected randomly. As samples are usually cut from whole commercial facets, samples from the facet edges are preferred, that include at least one original edge to be able to make predictions on the behaviour of these protected edges.

### 4.2. Sample measurements

All samples must be characterized before and after being exposed to the accelerated testing in the laboratory. This includes the optical analysis and reflectance measurements. A visual check is also done if the samples possess any obvious macroscopic damages. Then, a microscopic scan of the silver layer is conducted. Reflectance measurements include solar-weighted hemispherical reflectance as well as monochromatic specular reflectance. Measurements are conducted following the actual Solar Paces reflectance measurement guideline [1].

#### 4.2.1. Reflectance

The spectral hemispherical reflectance shall be measured in the wavelength range of λ=[320,2500] nm, using 5 nm intervals at near-normal incidence angle, θ≤15° with a spectrophotometer, equipped with an integrating sphere of 150 mm diameter. The data must be evaluated with a reference reflectance standard (calibrated in the range 320-2500 nm). Following ASTM Standard E903 82 (92), the solar-weighted hemispherical reflectance, \( \rho_{s,h}(\lambda, \theta, h) \), can be calculated by weighting the spectral hemispherical reflectance, \( \rho_{\lambda,h}(\lambda, \theta, h) \), with the solar direct irradiance on the earth surface for each wavelength, \( \lambda \), \( G(\lambda, h) \), according to Equation 4.1:

\[
\rho_{s,h}(\lambda, \theta, h) = \frac{\int_{\lambda_{c}}^{\lambda_{u}} \rho_{\lambda,h}(\lambda, \theta, h) \cdot G_b(\lambda) d\lambda}{\int_{\lambda_{c}}^{\lambda_{u}} G_b(\lambda) d\lambda}
\]  

(4.1)

For European and North American latitudes, typical solar irradiance spectra are given by the current standard ASTM G173-03 (direct irradiance) for air mass AM 1.5 [3]. The wavelength range of the solar spectral irradiance is λ=[280, 4000] nm. Because the mid-infrared range has a low impact and it is practically more convenient for the measurement equipment, the relevant measurement range for
reflectance evaluation can be resized to $\lambda = [320, 2500]$ nm. Alternatively to the ASTM spectrum, the ISO 9050 can be used for the weighting.

The monochromatic specular reflectance, $\rho_{\lambda,\phi}(\lambda, \theta_i, \phi)$, must be also measured with a reflectometer portable specular reflectometer. To monitor the aging, it is sufficient to measure the specular reflectance at one defined wavelength in the range $\lambda = [400, 700]$ nm, $\theta_i \leq 15^\circ$ and $\phi$ in the range of $0 \leq \phi \leq 20$ mrad.

As a minimum, 5 monochromatic specular measurements and 3 spectral hemispherical measurements shall be taken on a sample of around 100x100 mm$^2$. The 5 monochromatic measurements obtained with a reflectometer shall be taken in the center of the sample and close to the 4 corners of the sample. The measurement shall not be taken closer than 10 mm to the sample edge or areas that have not been exposed to the testing conditions (e.g. due to the sample holder). The spectral hemispherical measurements obtained with a spectrophotometer shall be taken in the center of the sample. The sample shall be rotated after each measurement by 90° (to obtain measurements at 0°, 90° and 180°on the same position on the sample). The samples shall be measured in the exact same positions for each analysis. A mask or stoppers may be used to easily find the same measurement position again after exposure.

For materials that may suffer from glass corrosion, it is recommended to test at least one additional sample with a protective tape on the glass surface, so that the reflectance measurement of the reflective layer is not influenced by glass corrosion. The sample should be placed with the protective paint side facing upwards in the chamber. Reflectance values of protected and unprotected samples shall be compared after the durability test.

The specularity of a material can be determined as the ratio of specular to hemispherical reflectance:

$$S_{\lambda,\phi} = \frac{\rho_{\lambda,\phi}}{\rho_{\lambda,h}}$$

As the specular reflectance is usually measured at 660 nm, it is common to determine the specularity at this wavelength as well.

### 4.2.2. Further Corrosion/degradation parameters

Samples should be checked with eye (necessary photographs taken for recording purpose) for any changes in appearance that could indicate any form of degradation. Optical light microscope should be used to inspect the degree of silver agglomeration on the surface or any other microscopic degradation not detectable by other means. The degree of coverage and the size of the corrosion patches with time under the relevant testing conditions should be noted.

The three main parameters to be detected are:

- **Edge corrosion penetration**: corrosion that is penetrating into the silver layer coming from the original (protected) edges of the samples. Usually the maximum penetration depth is determined.

- **Localized spot density**: local corrosion spots are counted with the naked eye or by automatic image detection software. Usually spot of diameters bigger than 200 $\mu$m are taken into consideration and the spot density (number per area) is calculated.

- **Blistering of protective paint**: Samples subjected to high humidity show the appearance of blisters in the protective back paint layers. The level is determined according to ISO 4628-2.

### 4.3. Current existing standards for testing
In 2018 the first standard specifically addressing the accelerated aging of solar reflectors was published [UNE 206016: Reflector panels for concentrating solar technologies, 2018]. It defines the important nomenclature and presents methods for optical characterization (reflectance) and the optical precision. Among other factors it includes a list of accelerated tests with their minimum test durations and the parameters to be applied (Table). The standard does not define any pass/fail criteria.

<table>
<thead>
<tr>
<th>Test</th>
<th>Minimum duration</th>
<th>Summary of testing conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Sprayed NaCl solution of 50 ± 5 g/l with condensation rate of</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.5 ± 0.5 ml/h on a surface of 80 cm²</td>
</tr>
<tr>
<td>Copper-accelerated acetic acid salt spray (CASS) ISO 9227</td>
<td>120 h</td>
<td>T: 50 ± 2°C, pH: 3.1 to 3.3 at 25°C</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sprayed NaCl solution of 50 ± 5 g/l and 0.26 ± 0.02 g/l CuCl₂</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Condensation rate of 1.5 ± 0.5 ml/h on a surface of 80 cm²</td>
</tr>
<tr>
<td>Condensation ISO 6270-2 [5]</td>
<td>480 h</td>
<td>T: 40±3°C, RH: 100%</td>
</tr>
<tr>
<td>Combined thermal cycling and humidity</td>
<td>10 cycles</td>
<td>4 h at 85°C, 4 h at -40°C, Method A: 16 h at T: 40°C and 97±3% RH,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Method B: 16 h at T: 85°C and 85±3% RH or 40 h at T: 65°C and 85±3% RH</td>
</tr>
<tr>
<td>UV/Humidity ISO 16474-3 [6]</td>
<td>2000 h</td>
<td>1 cycle: 4h at UV exposure at 60±3°C followed by 4h at 100% RH at 50±3°C</td>
</tr>
</tbody>
</table>

It was shown in different investigations [2] that the proposed minimum durations of this standard were very low and unable to provoke considerable degradation, even for reflector materials with quite weak durability. Sutter, et al. [3] published a work, proposing longer test durations for these accelerated aging tests, also including criteria to evaluate performance of reflectors in the initial state (Table), as well as after conducting the tests (Table). For the initial characterization only reflectance parameters are considered, because the absence of degradation is implied. The parameters for the characterization after performing the tests include admissible reflectance losses and appearing degradation effects (edge and spot corrosion, blisters).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar-weighted hemispherical reflectance (weighted with ASTM G173 reference spectrum)</td>
<td>$\rho_{\lambda,h}$</td>
<td>$[0.948, 1] [0.941, 0.948] [0, 0.941]$ exceeds state of the art state of the art below the state of the art</td>
</tr>
<tr>
<td>Solar-weighted hemispherical reflectance (weighted with ISO 9050 reference spectrum)</td>
<td>$\rho_{\lambda,ISO}$</td>
<td>$[0.945, 1] [0.938, 0.945] [0, 0.938]$ exceeds state of the art state of the art below the state of the art</td>
</tr>
<tr>
<td>Hemispherical reflectance at 660nm</td>
<td>$\rho_{\lambda,h}$</td>
<td>$[0.962, 1] [0.955, 0.962] [0, 0.955]$ exceeds state of the art state of the art below the state of the art</td>
</tr>
<tr>
<td>Near-specular reflectance at 660nm and 12.5 mrad</td>
<td>$\rho_{\lambda,\phi}$</td>
<td>$[0.960, 1] [0.953, 0.960] [0, 0.953]$ exceeds state of the art state of the art below the state of the art</td>
</tr>
<tr>
<td>Specularity at 660 nm and 12.5 mrad</td>
<td>$S_{\lambda,\phi}$</td>
<td>$[0.996, 1] [0, 0.996]$ state of the art below the state of the art</td>
</tr>
</tbody>
</table>
### Table 4.3: Proposed acceptance criteria for silvered-glass mirror testing according to the minimum testing time proposed in UNE 206016:2018.

<table>
<thead>
<tr>
<th>Test Condition</th>
<th>Admissible $\Delta \rho_{s,h}$</th>
<th>Admissible $\Delta \rho_{\lambda,\varphi}$</th>
<th>Admissible edge corrosion $l_{corr}$</th>
<th>Admissible spot corrosion $d_{corr}$</th>
<th>Admissible blistering level</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSS, 480h</td>
<td>Slight (≤0.004)</td>
<td>Slight (≤0.004)</td>
<td>≤ 0.1 cm</td>
<td>≤ 0.01 cm$^2$</td>
<td>0(S1)</td>
</tr>
<tr>
<td>CASS, 120h</td>
<td>None (≤0.002)</td>
<td>None (≤0.002)</td>
<td>≤ 0.1 cm</td>
<td>≤ 0.01 cm$^2$</td>
<td>0(S1)</td>
</tr>
<tr>
<td>Condensation, 480h</td>
<td>None (≤0.002)</td>
<td>None (≤0.002)</td>
<td>≤ 0.1 cm</td>
<td>≤ 0.01 cm$^2$</td>
<td>≤1(≤S4)</td>
</tr>
<tr>
<td>TCH, 10 cycles</td>
<td>None (≤0.002)</td>
<td>None (≤0.002)</td>
<td>≤ 0.1 cm</td>
<td>≤ 0.01 cm$^2$</td>
<td>≤1(≤S4)</td>
</tr>
<tr>
<td>UVH, 2000h</td>
<td>Slight (≤0.004)</td>
<td>Slight (≤0.004)</td>
<td>≤ 0.1 cm</td>
<td>≤ 0.01 cm$^2$</td>
<td>≤1(≤S4)</td>
</tr>
</tbody>
</table>

Alternative testing protocols were developed in the RAISELIFE project: a comparative testing protocol and a lifetime prediction protocol (see Deliverable 1.5 of RAISELIFE project). The comparative testing has the purpose of comparing different materials directly. It is simple (single tests) and aggressive enough to provoke sufficient degradation to evaluate and to rank the materials accordingly. Test results are compared with degradation from outdoor exposure experiments conducted in RAISELIFE. For the lifetime prediction protocol, test procedures were investigated to provoke exactly the same degradation mechanisms as found after outdoor exposure. They are based on correlations of the degradation development between outdoor and accelerated tests, enabling to predict the material behavior for long time outdoor exposure on sites with different corrosivity and erosivity classes.

#### 4.4. Anti-soiling coatings

Anti-soiling coatings are usually applied on state of the art silvered-glass mirrors. Normal testing protocols, as detailed in section 4.3, can be used for testing of the coatings as well.

Experience from long term outdoor campaigns has shown, that mechanical stability is one of the most important issues, when evaluation these coatings and their durability. Cleaning, especially contact cleaning methods with brushes for example, as well as erosion by airborne particles were detected as main stresses, which can contribute to the degradation of the coatings. The surface of conventional glass mirrors possesses a high hardness and is not easily scratched. Coatings used to produce the anti-soiling effect often show lower hardness values. That is the reason why certain types of coatings show scratches or punctual defects as well as the possible delamination of the coating layer itself.

To assure the mechanical stability of the coatings, the performance of several mechanical tests is recommended. The most commonly used tests are:

- Erosion testing to simulate the effect of airborne particles (see details in section 4.5).
- Brush resistance or Washability test to simulate cleaning procedure (according to ISO11998). In the standard 200 cycles are defined as a minimum duration. Longer durations are recommended to simulate harsher conditions.
- Abrasion resistance test (usually performed with a Taber type apparatus, e.g. as defined in UNE206016 section 7.2.).
4.5. Erosion testing

The first step on simulating experimentally the erosion degradation of solar reflectors by sand particles, is to make sure that the device used for those tests is delivering results as repeatable as efficient.

The employed test bench in MAScIR’s laboratory is a horizontal ejection system. The pressurized air and sand particles are homogenized and mixed through a horizontal tube, after the mixture, the particles are propelled and ejected towards the target surface at a fixed air speed and a controlled inclination angle.

Before the conduction of the accelerated tests, a calibration campaign should be conducted. This campaign aims to assess the variation of the different settled parameters and their effects on handling the tests. The parameters set up are detailed and presented below.

DLR/CIEMATs erosion testing system works in similar manner. It consists of a fan and wind tunnel, in which particles can be injected. For further description see Deliverable 1.5 of the RAISELIFE project.

4.5.1. Calibration steps

The erosion degradation caused by sand particles depends on several parameters. Those controlled in the test bench are: the air velocity, impact angle and the amount of the ejected sand mass.

Air velocity

This parameter represents the wind speed values collected from the meteorological stations at the exposure sites. The air speed is adjusted by combining the delivered air pressure and the standoff distance between the homogenization tube outlet and the position where the sample is positioned. The sample position is adjusted on a graduated scale ranging from 0 to 100 cm from the homogenization tube. Depending on the desired air speed value, a couple of (pressure, distance) is determined to be fixed in the equipment. The test values should not exceed the maximum wind speed on sites and should be as important as to carry the sand particles and to transform them to airborne.

Impact angle

The formed angle between the sand particle and the reflector surface can vary in a wide range (from 0 to 180°); the selected values should represent as much the reflectors tracking. Specific angles should also be tested to assess the behavior on the extreme life service conditions (normal angle (90°) for example).

Mass rate per area

In order to compare the results of different tests made at different conditions (distance from the homogenization tube, air speed and impact angle), it should be ensured that samples are receiving the same rate of sand. To that concern, a parameter defined as the received mass per sample is introduced.

This parameter represents the mass of sand received by the sample while facing the flux delivered by the homogenization tube and takes into account two restrictions with regards to sample orientation; the first one consists on identifying the minimum sand mass that can generate visible degradation at lower conditions (namely the low wind speed and the low impact angle); the degradation is quantified by the optical properties changes, namely, reflectance loss. The second restriction is the maximum sand mass after which we have a total deterioration of the samples tested at higher or extreme conditions (very high velocity with normal impact angle).

For example, ejecting the same sand mass on a surface oriented at 90° with a speed of 25 m/s and 5 m/s will end up with different sand mass received by the sample’s surface. For that reason, we’ve set this parameter (received mass) helping to unify the mass received by all test samples in the totality of
configurations (impact angle and air velocity), so the results and then the reflectance losses could be comparable.

The appropriate sand mass received per sample is determined through a set of tests; these tests consist on ejecting a random mass of sand in the extreme and lower conditions and then visualize the surface state (namely, the reflectance loss) to decide if the ejected mass is sufficient or needs to be adjusted.

One of the proposed solutions to quantify the sand mass received at the sample’s surface, are tests on the carton samples pasted with silicon to catch the particles received. The silicon paste serves as particles catcher and helps to quantify the amount of sand received by samples (regardless their material) in the different scenarios (the multitude angles and speeds).

Before the tests, the carton sample pasted with silicone is weighted and also the initial mass to eject. The carton sample is then introduced in the test chamber. After propelling the sand mass, the weight of the carton sample is measured, the received sand mass by the surface samples is then defined as the difference between the weights of carton sample after test minus the carton sample weight before the tests (carton + Silicon paste).

Once the received mass for all the test conditions is fixed, the calibration work switch to determine the required sand mass to eject in the equipment and will deliver the received sand mass on the samples surface.

As a maintenance operation, the setup should be cleaned after each test from the sand particles propelled to not affect the subsequent tests.

For representative mass rates per area which simulate outdoor environments see Deliverable 1.5 of the RAISELIFE project.

**Samples**

The tested samples should be cleaned up; their initial reflectance should be measured all over the surface (not only in the center) to collect a maximum data points on the reflectance variation.
5. **Best practices accelerated aging of secondary reflectors in the solar field (BSII, SOL, Fraunhofer, CIEMAT, DLR)**

In this section, the best practice on accelerated aging of secondary reflectors. The goal is to provide all parties which conduct any form of accelerated aging tests with useful information on key aspects to keep in mind and parameters to be fulfilled.

5.1. **Definition of parameters concerning the samples**

Three samples coming from the normal production must be included in every accelerated aging test to have enough statistical information. They must be selected randomly from the whole set of samples produced. During accelerated aging testing, coated secondary reflector samples should be handled with powder-free gloves (e.g. nitrile gloves or equivalent). Scratches and finger contact of the coated surfaces should be avoided.

It should be noted most coating systems improve with a 24-48 h 400 °C anneal. This means that their reflectance increases and also the inter-layer adhesion improves, which increases their resilience to humidity or wet-corrosive conditions after annealing.

5.2. **Measurement of material quality**

The measurement of the material quality should be performed the same way it is done for the primary reflectors. For details see section 4.1.

5.3. **Selection of tests and adequate test parameters**

In general, the following standard tests are recommended, depending on the known climate of operation location. The goal in this case is to check the general suitable of the reflectors according to the minimum testing time recommended in UNE 206016.

<table>
<thead>
<tr>
<th>Test</th>
<th>Standard</th>
<th>Conditions</th>
<th>Duration</th>
<th>Characterization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Condensation</td>
<td>ISO 6270-2-CH UNE 206016</td>
<td>$T=40^\circ\text{C}, RH=100%$</td>
<td>480 h</td>
<td>0, 480 h</td>
</tr>
<tr>
<td>NSS</td>
<td>ISO 9227 UNE 206016</td>
<td>$T=35^\circ\text{C}, RH=100%, [NaCl]=50\text{g/l}, pH=[6.5-7.2]$</td>
<td>480 h</td>
<td>0, 480 h</td>
</tr>
<tr>
<td>CASS</td>
<td>ISO 9227 UNE 206016</td>
<td>$T=50^\circ\text{C}, RH=100%, [NaCl]=50\text{g/l}, [CuCl}_2=0.26\text{g/l}, pH=[3.1-3.3]$</td>
<td>120 h</td>
<td>0, 120 h</td>
</tr>
<tr>
<td>UV+HUMIDITY</td>
<td>ISO 16474-3 UNE 206016</td>
<td>- 4h dry $T=60^\circ\text{C}$ to 0.83 W/m$^2$ (340 nm) - 4h condensation to $T=50^\circ\text{C}$ without UV and RH not controlled</td>
<td>1000 h</td>
<td>0, 1000 h</td>
</tr>
<tr>
<td>Taber</td>
<td>ISO 9211-4.741 UNE 206016</td>
<td>Alternative linear movement of an abrasive head (CS10 ¼”) at room temperature</td>
<td>100 cycles</td>
<td>0, 100 cycles</td>
</tr>
</tbody>
</table>

In addition, the following tests must be applied to analyse the suitability of the reflector material for a specific operating temperature, $T_{op}$. This value shall be obtained by simulation analysis, considering the real operating solar flux and several options regarding ambient conditions and cooling systems.
Table 4.5: Special accelerated aging tests to be applied to the secondary mirrors (depending on the operating temperature, $T_{op}$). *: To be decided, depending on the ambient conditions

<table>
<thead>
<tr>
<th>Test</th>
<th>Goal</th>
<th>Conditions</th>
<th>Duration</th>
<th>Characterization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Damp heat</td>
<td>Night conditions</td>
<td>$T=85^\circ\text{C}, RH=85%$ (IEC 62108)</td>
<td>TBD*</td>
<td>Each 250 h</td>
</tr>
<tr>
<td>Muffle Oven</td>
<td>Operation under constant temperature</td>
<td>$T={T_{op}-20^\circ\text{C}, T_{op}, T_{op}+20^\circ\text{C}}$</td>
<td>2000 h</td>
<td>Each 250 h</td>
</tr>
<tr>
<td>Solar Furnace</td>
<td>Operation under real concentrating radiation</td>
<td>$T = T_{op}$</td>
<td>The maximum possible</td>
<td>Every day</td>
</tr>
<tr>
<td>Thermal cycles</td>
<td>Starting up and Shut down of the plant</td>
<td>From ambient to $T_{op}$</td>
<td>250 cycles (1 cycle = 1 hour)</td>
<td>0, 250 cycles</td>
</tr>
</tbody>
</table>

Finally, the following tests are recommended, to check the possible degradation of the secondary reflectors due erosion by airborne (sand storm) and abrasion by cleaning (washability).

Table 4.6: Special accelerated aging tests to be applied to the secondary mirrors to analyse the effect of erosion and abrasion.

<table>
<thead>
<tr>
<th>Test</th>
<th>Standard</th>
<th>Conditions</th>
<th>Duration</th>
<th>Characterization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstorm</td>
<td>---</td>
<td>70 g of dust to 20 m/s</td>
<td>1 cycle = 45 min</td>
<td>0, 1 cycle</td>
</tr>
<tr>
<td>Washability</td>
<td>ISO 11998</td>
<td>Linear movement of a brush head back and forth at room conditions under ambient running water</td>
<td>200 cycles</td>
<td>0, 200 cycles</td>
</tr>
</tbody>
</table>
6. Best practices on accelerated aging of receivers for solar towers (DLR, CIEMAT, BSII, Fraunhofer, DFI, INTA, PROMES)

In this section, best practices on accelerated aging of receivers for solar towers are presented. The goal is to provide all parties which conduct any form of accelerated aging tests with useful information on key aspects to keep in mind and parameters to be fulfilled.

This chapter includes specific subsections on receiver coating characterization, accelerated aging testing of receiver coatings under concentrated solar flux, accelerated aging testing in muffle furnaces and environmental accelerated aging testing.

6.1. Introduction

6.1.1. Foreword

In order to develop standard accelerated aging test procedures for receiver coatings applied on solar tower receivers, some knowledge is required about normal operating conditions. However, the access to field data is scarce. So far, operational data has been publicly disclosed only for Pyromark 2500 and the SolarTwo pilot plant operated in the 1980’s. Today, only a few companies worldwide are designing and building external receivers for solar tower power plants, operational data thus remains yet confidential. Furthermore, the receiver design is not yet standardized, contrary to parabolic trough concentrators. This results in different piping diameters and substrate selection, depending on the heat transfer fluid and the operating temperature. Furthermore, commercial solar tower power plants have been developed in recent years, long term operational data (flux and temperature maps) is thus not yet available. The feedback for recoating operations is also limited. Given the height of solar tower receivers (> 250 m), the access is quite restricted for in-situ characterization of environmental parameters.

6.1.2. Allowable Flux Density and Service Lifetime

Based on literature, one key constraint for the design and simulation of a solar receiver is the allowable flux density (AFD) \[4\]. The heat transfer fluid (HTF) constrains both the maximum flux density and skin temperature. For a molten salt HTF, Vant Hull for example reports respectively an AFD of 850 kW/m\(^2\) at the inlet, where the fluid temperature reaches 290 °C, and 250 kW/m\(^2\) at the outlet, where the fluid temperature reaches 565 °C. Beyond this fluid temperature, current molten salt formulations become corrosive. Taking into account thermal conductivities, the maximum coating skin temperature is expected to reach at least 600 °C.

The receiver is designed for a service lifetime of 30 years. This lifetime applies primarily for the mechanical design (i.e. fatigue analysis), taking into account thermal stresses. The receiver coating can be re-applied periodically, minimizing the Levelized Cost of Coating \[5\], i.e. balancing the coating optothermal performance, its durability and its cost of application. A typical re-application frequency of minimum 5 years is considered, implying a downtime of the power plant for a couple of weeks, coupled with other maintenance activities.

6.1.3. Degradation of receiver coatings

As reported in \[6\], two degradation modes are identified:

- Optical degradation, i.e. loss of solar absorptance;
• Mechanical degradation, i.e. formation of micro-cracks.

Within Raiselife project, the focus has been orientated towards the quantitative evaluation of optical degradation, both in terms of solar absorptance and thermal emittance. Metallurgical analysis of coating structure has also been carried out after testing. Mechanical degradation has only been qualitatively analyzed, applying for example the cross-cut test method. Furthermore, it is worth observing that optical measurements are performed locally at a few spots on material samples. Subsurface defects and superficial microscopic defects are thus not detected with this method, while metallurgical analysis allows an in-depth understanding of degradation mechanisms. Several degradation mechanisms can be identified for receiver coatings, here is a non-exhaustive list:

• High temperature oxidation at the interface between the metal substrate and receiver coating;
• Corrosion induced by salts present in the atmosphere;
• Erosion induced by sandstorms;
• Mechanical defects: micro-cracks, peeling, flaking, spalling, etc.,
• Optical degradation, such as optical fading.

6.1.4. Durability testing

There are three main categories of aging tests to assess a receiver coating durability:

• Thermal cycling under concentrated solar flux;
• Muffle furnace testing, isothermal and cyclic,
• Environmental testing in climate chambers.

These tests are described further in more details. These aging tests can be combined to induce different degradation mechanisms, instead of investigating separate degradation mechanisms.

Thermal cycling under concentrated solar flux allows to approximate realistic conditions, in terms of flux density, temperature levels and temperature/flux gradients. However, these tests are weather dependent, the flux density homogeneity depends on the quality of the solar concentrator, accurate in-situ temperature measurement is not trivial and the control of gradients depends on the particular setup. One can distinguish between slow and fast thermal cycling. Slow cycling reproduces realistic operation, while fast cycling reproduces transient cloud passages.

Muffle furnace tests includes both isothermal and thermal cycling tests for long exposure time (> 1000 hours). In contrast to thermal cycling under concentrated solar flux, muffle furnace testing allows for more control as this kind of experiments is not weather dependent. This is especially relevant for the curing of wet coatings. On the other hand, the influence of concentrated solar flux, especially concentrated ultraviolet radiation, is not included in this test. Some muffle furnaces allow for atmosphere control, however the most representative case is a standard atmosphere, i.e. dominance of oxygen. These conditions are also met with under concentrated solar flux. Service lifetime predictions have been recently derived for solar receiver coatings [6], focusing only on muffle furnace testing. The long term testing at different temperature levels allows the development of Arrhenius models.

Environmental testing is performed in climate chamber tests applying standard test conditions, defined for other kind of materials, for instance reflectors or photovoltaic modules. Five different climate chamber tests have been implemented: Damp Heat (DH), Humidity Freeze (HF), Sand Erosion (SE), Neutral Salt Spray (NSS), Condensation. These tests are further described in the corresponding paragraph.
6.2. Receiver coating characterization

6.2.1. Optical characterization

Receiver coatings can be optically characterized at room temperature with two spectrophotometers, respectively measuring the spectral hemispherical reflectance in the wavelength ranges 0.28…2.5μm and 2…16 μm (blue curve in Figure 4.1 for a Pyromark 2500 coating). These spectral measurements are weighted to derive solar weighted absorptance $\alpha_s$ and thermal emittance $\varepsilon_{th}$. These figures of merit are combined to calculate a performance criterion, i.e. the coating thermal efficiency $\eta_{coating}$, at a skin temperature of 650°C (for a T91 substrate) and a flux density corresponding to the experimental flux (between 250 and 700 kW/m$^2$).

6.2.2. Solar Absorptance

The spectral hemispherical reflectance $R(\lambda)$ is measured at room temperature using a Perkin Elmer UV-VIS-NIR Lambda 1050 spectrophotometer, with a 150 mm integrating sphere and an incidence angle of 8°. Spectral measurements are performed in 5 nm steps from 280 to 2500 nm. Each coated sample is measured at three positions. The solar absorptance $\alpha_{sol}$ is calculated according to Equation 4.3 by weighting spectral measurements with the ASTM G173-03 reference spectrum for solar direct normal irradiance $G_{sol}(\lambda)$ at an air mass (AM) of 1.5 (yellow curve in Figure 4.1).

$$\alpha_{sol} = \frac{\int_{\lambda_1}^{\lambda_2} [1 - R(\lambda)] \cdot G_{sol}(\lambda) \cdot d\lambda}{\int_{\lambda_1}^{\lambda_2} G_{sol}(\lambda) \cdot d\lambda}$$

(4.3)

The integrands in the numerator and denominator are discretized into wavelength bands to accommodate the available data and then summed to approximate the integrals, i.e. $\lambda_1=280$nm; $\lambda_2=2500$ nm; $d\lambda=5$nm.

Figure 4.1: Reference for direct solar spectrum radiation, blackbody spectrum radiation and Pyromark reflectance
6.2.3. Thermal Emittance

The spectral hemispherical reflectance $R(\lambda)$ is measured at room temperature using a Perkin Elmer Frontier-FTIR spectrophotometer, with a diffuse gold coated 76.2 mm integrating sphere and an incidence angle of 12°, delivered by Pike Ltd Technologies. Spectral measurements are performed in 4 nm steps from 2000 to 16000 nm. Each coated sample is measured at three positions. Spectral measurements are contrasted with the gold integration sphere background as a zeroline and an infragold diffuse uncalibrated reference standard as a baseline. A spectral mismatch is observed when comparing UV-VIS-NIR and raw FTIR data in the wavelength range from 2000 to 2500 nm...

The thermal emittance $\varepsilon_{th}$ is calculated at any temperature $T$ (K) according to Equation 4.4, by weighting spectral measurements from $\lambda_1=280$ nm to $\lambda_3=16000$ nm with the corresponding blackbody radiation spectrum, defined by Planck’s law (Equation 4.5). The spectrum irradiance of a 600°C blackbody radiation is presented in Figure 4.1 (red curve).

$$\varepsilon_{th}(T) = \frac{\int_{\lambda_1}^{\lambda_3} [1-R(\lambda)]L_{BB}(\lambda, T) \cdot d\lambda}{\int_{\lambda_1}^{\lambda_3} L_{BB}(\lambda, T) \cdot d\lambda} \quad (4.4)$$

$$L_{BB}(\lambda, T) = \frac{2\pi hc^2}{\lambda^5 \cdot \left[\exp\left(\frac{hc}{\lambda kT}\right) - 1\right]} \quad (4.5)$$

In Equation 4.3, the integrands in the numerator and denominator are discretized into wavelength bands to accommodate the available data and then summed to approximate the integrals. In Equation 4.5, $c$, $k$ and $h$ are universal physical constants, which respectively correspond to the speed of light in vacuum ($3.00\times10^8$ m·s$^{-1}$), Planck’s constant ($6.63\times10^{-34}$ J·s) and Boltzmann’s constant ($1.38\times10^{-23}$ J·K$^{-1}$).

6.2.4. Opto-Thermal Efficiency

Solar absorptance $\alpha_s$ and thermal emittance $\varepsilon_{th}(T)$ can be combined into a single performance criterion, i.e. coating opto-thermal efficiency $\eta_{coating}$, defined in (Equation 4.6) as a function of the absorber temperature $T_{abs}$ (K) and the concentrated solar flux $Q_{sol}$ (W/m$^2$), while assuming negligible convection losses. This criterion can be derived with respect to solar absorptance and thermal emittance to assess their respective impact on thermal efficiency (Equation 4.7).

$$\eta_{coating} = \frac{\alpha_s \cdot Q_{sol} - \varepsilon_{th} \cdot \sigma \cdot T_{abs}^4}{Q_{sol}} \quad (4.6)$$

Where $\sigma$ corresponds to Stefan Boltzmann’s universal physical constant ($5.67\times10^{-8}$ W/m$^2$·K$^4$).

$$\frac{d\eta_{coating}}{d\alpha_s} = \frac{d\eta_{coating}}{d\varepsilon_{th}} = \frac{-\sigma \cdot T_{abs}^4}{Q_{sol}} \quad (4.7)$$

Assuming a solar flux of 500 kW/m$^2$ and a skin temperature of 650 °C, $d\eta/d\varepsilon_{th}$ equals -0.082. So, for this conditions, increasing solar absorptance by 1% has the same impact on thermal efficiency as reducing...
thermal emittance by $1/0.082=12.2\%$. Thermal efficiency is thus more sensitive to solar absorptance than thermal emittance at this working point.

6.2.5. Acceptance/fail criteria

High solar absorptance (HSA) receiver coatings have a nominal solar absorptance value above 96%. A loss higher than 0.5%-pp can be considered critical for the efficient operation of the power plant. Alternatively, a solar absorptance lower than 95% has been defined as failure criterion in the literature [6].

Among the three tests presented above, the slow solar cycling combined with a condensation phase (50 cycles + 100h of condensation + 50 cycles) allows the detection of some samples failure (with performance losses between 0.7 and 3.7%). In terms of duration, this kind of aging treatment represents around 100h of cycles.

For the fast solar cycling methodology, the RAISELIFE samples have suffered 200 cycles in approximately 14 hours. For the extended fast solar cycling methodology, 40 cycles in 14 hours have been applied. Despite the severe thermal gradient and flux gradient applied at each cycle, this kind of solar cycling did not deteriorate significantly the samples of the project. The duration of the experimentation is not long enough to conclude about the evolution of the coatings.

6.3. Thermal cycling under concentrated solar flux

6.3.1. About the samples

Depending on the facility, the layout of the samples to be tested is different. In a device like the SAAF at PROMES-CNRS laboratory (Odeillo, France), the accepted samples are flat square samples, with a maximal thickness of 6mm (usually around 3mm), and a size of 30x30 mm² or 50x50 mm². The aging stress is mainly applied in the center, in a region of 20x20 mm². Furthermore, only one sample at a time can be tested, at the focal point of the parabola. In a device like the dish used at PSA (Almeria, Spain), the samples are tubular (length 40 mm, outer diameter: 31.8 mm, wall thickness: 5 mm). The test bench allows the aging of 15 samples simultaneously, while the flux density homogeneity is controlled within +/- 25%.

6.3.2. Selection of tests and adequate test parameters

Different kind of aging cycles have been experimented during the RAISELIFE project. The common parameter between them is the **maximal temperature reached**, corresponding to the operational conditions. For example, a coating placed on a T91 substrate should work up to 650°C. So, it is important to define a cycle during which the front face of the sample reaches this temperature without exceeding it. On one hand, if we don’t reach the expected temperature, we can’t test the resistance of the material to the operational conditions. On another hand, if we exceed it, some unexpected mechanisms can deteriorate the surface disproportionately comparing with a real aging in CSP conditions.

The main differences between the cycles are the test parameters below:

- The maximal level of flux: it can be equivalent to the operational flux in a CSP plant, lower or higher.
The duration of the cycle: the time during which the sample is at the maximal temperature, under the maximal flux; and the time during which the sample is at a lower temperature, under a lower flux.

The heating and cooling gradient: the rate of temperature and flux increase/decrease.

The parameters like humidity and corrosive conditions are tested separately. They are detailed in the following section “Environmental aging tests”.

The three main kind of cycles experimented under solar flux in dish concentrator are presented here. The values of maximal flux and temperature considered here for the examples correspond to a coating applied on T91 substrate.

**Slow solar cycling**

Temperature and flux profile of the slow solar cycling are illustrated in Figure 4.2.

One cycle consists of 3 sequences:

- **Heating**: All samples are first heated from 200 to 650 °C at a maximum heating rate of 30 °C/min. The average solar flux on the receiver panel is gradually increased from 40 to 250 kW/m².

- **Dwell time**: the maximum skin temperature is then maintained at 650 °C for 30 minutes. The average solar flux is maintained at 250 kW/m² for 30 minutes.

- **Cooling**: All samples are cooled from 650 to 200 °C at a maximum cooling rate of -30 °C/min. The average solar flux is reduced gradually from 250 to 40 kW/m².

In order to increase the impact of dish aging cycles, a condensation test can be added in between the aging procedure. For example, it is possible to apply first an isothermal muffle furnace test at the maximum temperature for 1000 hours, then 50 aging cycles at the dish concentrator, then 100h of condensation (in a climate chamber), and then 50 more cycles at the dish concentrator.

**Fast solar cycling**

Unlike the previous cycle, the flux profile is square-shaped: it switches between the low value and the high value in less than one second. As a consequence, the temperature increases quickly until the required maximal temperature (see Figure 4.2). So the parameters are as follows:

- **Heating-Dwell time**: The average solar flux is suddenly increased from 250 to 500 kW/m², and is then maintained at 500 kW/m² for 200 seconds. So, the sample is heated from 450 to 650 °C at a maximum heating rate of 30 C/s (in the very first seconds of the cycle).
• **Cooling:** The solar flux is suddenly reduced from 500 to 250 kW/m² and is then maintained at 250 kW/m² for 200 seconds. The sample is cooled at a maximum cooling rate of -25°C/s (in the very first seconds of the phase) from 650 to 450°C.

![Figure 4.3: Example of temperature, flux profile and gradient temperature of fast solar cycling, for a sample made of T91 substrate.](image)

**Extended fast solar cycling**

This cycle is similar to the previous one, but with a longer dwell time, and a flux slightly higher than the nominal flux considered: so, during the “top phase”, the flux is maintained at 700 kW/m² for 20 minutes. But, the maximal temperature of 650°C is respected.

### 6.4. Muffle furnace testing

#### 6.4.1. Isothermal furnace tests

Isothermal muffle furnace tests are typically performed at three temperature levels. For a T91 or VM12 substrate, these levels are defined at 600 °C, 620°C and 650 °C. For an Inconel substrate, these levels are defined at 680 °C, 710 °C and 750 °C. Generally, the mid-temperature level is set at the expected operating temperature and the two other temperatures are defined within a range of +/- 20-30 °C. This allows the development of Arrhenius models, which are inherently exponential.

The duration of isothermal testing should be at least 1000 hours. The test protocol defined in Raiselife includes a total exposure time of 2000 hours, with a periodical optical analysis every 500 hours.

#### 6.4.2. Thermal cycling

Thermal cycling can also be performed in muffle furnaces. The construction of the muffle furnace determines the heating and cooling gradients, which are non typically non linear. The cycle includes three sequences:

- Heating from 200 to maximum temperature setpoint, within ~ 25 minutes;
- Holding the temperature for 30 minutes;
- Cooling from maximum temperature to 200 °C in about 25 minutes.

The total number of cycles is set to 200 cycles, with a periodical optical analysis every 50 cycles.

### 6.5. Environmental accelerated aging tests

The parameters for environmental accelerated aging tests are listed below in Table . For each coating formulation, 3 flat coated samples (50x50 mm²) are exposed in the corresponding climate chambers. The sand erosion test is non standard, while other environmental tests are derived from standard tests for other coatings.
and applications. The relevance of each test depends on the expected environmental load for the power plant site, for example the corrosivity class. Meteorological conditions at the receiver height (> 200 meters above ground) may differ from the ground conditions, especially for sand erosion (particle size, wind profiles). The neutral salt spray is particularly relevant if the power plant is located near the coast, because of the saline atmosphere. Damp Heat (DH) and Humidity Freeze (HF) tests are relevant when the receiver is not in operation, i.e. during night or in the absence of sun, with a humid atmosphere.

<table>
<thead>
<tr>
<th>Test</th>
<th>Sand Erosion (SE)</th>
<th>Damp Heat (DH)</th>
<th>Humidity Freeze (HF)</th>
<th>Neutral Salt Spray (NSS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard</td>
<td>MIL-STD 810 G</td>
<td>IEC 62108, Test 10.7b</td>
<td>IEC 62108, Test 10.8</td>
<td>ISO 9227</td>
</tr>
<tr>
<td>Duration</td>
<td>-</td>
<td>1000 hours</td>
<td>1500 hours</td>
<td>480 hours</td>
</tr>
<tr>
<td>Parameters</td>
<td>20 m/s; 3x 70 g blowing dust</td>
<td>$T_{\text{amb}}$: 65 °C RH: 85 %</td>
<td>$T_{\text{amb}}$: -40 to 65 °C RH: max. 85 %</td>
<td>$T_{\text{amb}}$: 35 °C pH 6.5 to 7.2 at 25 °C</td>
</tr>
</tbody>
</table>

7. Best practices accelerated aging of receivers for parabolic-trough collectors in the solar field (SOL, CIEMAT)

7.1. Introduction

Heat collector elements (HCE) or solar receiver tubes are a key element in the development and performance of parabolic trough and Fresnel collectors. They are the responsible to collect solar energy and to interchange the heat collected to the heat thermal fluid (HTF). Concentrated solar power (CSP) technologies present a large operation experience, mainly with parabolic troughs to produce electricity and Fresnel technology in a lower extend. Solar receiver tubes need to have durability higher than twenty years in operation and at this moment it has not been reached in any parabolic trough commercial power plant. With Fresnel collector plants, we do not have enough accumulated information yet.

During last ten years, several companies are producing commercial HCE for parabolic trough collector plants and this strong competition has produced a strong evolution in HCE during this time. But there is no evidence that durability problems have been solved with the new designs and improvements. Operational problems that seemed solved are appearing now with new HCE installed during last five years. It is necessary to consider that one the main operation and maintenance cost in a solar power plant is the replacement of HCE due to breakage or degradation. Total cost is HCE cost, replacement cost and the lost in electricity production due to the need to close the complete collector line where the HCE is located.

Solar receiver tubes used in CSP used to be evacuated to reduce thermal losses by conduction and convection. Vacuum provides a better thermal performance but its produces degradation problems in HCE that have not been successfully solved yet and tube cost is increased a lot. For higher concentrating ratios it is recommended to use evacuated tubes but for lower ones, such as in process heat that requires lower operation temperature, it is better to avoid vacuum to obtain a cheaper component.

Non evacuated tubes present an additional thermal stability problem because most of commercial selective absorbers are not stable in air at higher temperatures (250-350°C)
Main challenges to be fulfilled in the future are to increase durability and to reduce cost and maintenance. In order to increase durability, vacuum maintenance is the major challenge because thermal losses and selective absorber stability are directly dependent on vacuum level. Selective absorber thermal stability, both in vacuum and air, has to be improved to raise operation temperature in solar thermal plants and in this way, to improve efficiency and to minimize damage if vacuum is lost.

Key components in a heat collector element are:

- Metallic tube material;
- Selective absorber;
- Antireflective coating;
- Glass to metal seal.

In this document, these key components are described and analyzed, including their characterization and durability tests required to qualify them. Some strategies to improve performance and operation tips are presented.

7.2. Metallic tube material

At this moment, all HCE producers are using AISI 316 or 321 stainless steel due to their better corrosion resistance and mechanical properties. They provide an improved behavior against other materials in the main CSP applications:

- Higher resistance against erosion and cavitation produced in direct steam generation plants (DSG) using water as heat thermal fluid (HTF);
- Lower hydrogen permeation with synthetic oil and organics such as Biphenyl/Diphenyl oxide systems, Hydrogen diffusion is the major drawback of this technology because of HTF thermal degradation and high hydrogen partial pressures are achieved in vacuum annulus [7];
- Corrosion resistance with molten salts [8], [9].

Carbon and low alloyed stainless steels have better thermal conductivity than high alloyed austenitic stainless steel and they are cheaper but these steels have lower corrosion resistance than austenitic stainless steel. Now, it is an increased interest in the replacement of high alloy stainless steel with low alloyed materials to reduce cost and to improve heat transfer along tube wall thickness.

7.3. Selective absorber

7.3.1. Introduction

Selective absorber is the main responsible of optical and thermal efficiency of a receiver tube. It absorbs concentrated solar radiation that reaches the metallic pipe and the collected energy is transferred to the HTF. Receiver tube thermal losses by conduction and convection are reduced with vacuum environment within metal and glass pipes and radiative losses are minimized by the low thermal emittance of the selective absorber.

Selective absorbers have to withstand temperatures between 30 and 50°C over nominal temperature depending on wall pipe thickness and pipe material. Absorber collects solar radiation and has to transfer
heat to the HTF, so increasing wall thickness and decreasing steel heat transfer coefficient lead to a higher absorber temperature [10].

Also the intensity distribution on the absorber surface has an impact on the stresses on the absorber system, as due to the concentrator system, usually one side of the absorber tube receives an overwhelming fraction of the total irradiation on the tube.

Main degradation processes in selective absorbers can be summarized as follows:

- **Thermal stress.** Temperature differences within the high temperature receivers on the one hand side, but also even for homogeneous temperature fields non-matching thermal expansion coefficients of adjacent layers may lead to thermally induced stresses on the individual layers. This in turn may induce flaking or chipping off of layers. Cracks are developed and barrier layers are destroyed locally. The problem may be facilitated by introducing special adhesion layers between problematic materials.

- **Oxidation.** If vacuum is lost in the receiver tube, a strong degradation is produced due to oxidation in high temperature absorbers. Metallic layers of the IR-mirror and/or the metallic particles in the cermet layer are subject to oxidation. It has to be considered that antireflective and barrier layers that protect absorber and IR reflector are quite thin layers and they do not protect effectively the absorber system against degradation.

- **Diffusion.** Diffusion processes may take place between substrate and absorber systems or within the individual absorber layers. So, it is required to use thin and dense barrier layers between substrate and IR reflector and, usually, between IR reflector and absorbing layer. Barrier layers of Al$_2$O$_3$ and SiO$_2$ have been successfully used to reduce diffusion.

### 7.3.2. Aging and durability

Up to now, there are no any international standard tests to qualify selective absorbers of the CSP absorber tubes. At the end of 2010, several countries are starting to create committees to developed adequate standard tests to these materials for CSP applications. Actually, each company performs their own tests to verify thermal stability, hydrogen diffusion and so on.

There are three main durability problems in the absorber tube related to the absorber coating:

- Selective absorber stability in vacuum and in air;
- Hydrogen diffusion through the SS tube and absorber coating;
- Thermal stress.

### 7.3.3. Thermal stability

Selective absorbers used by HCE producers have good thermal durability in vacuum at normal CSP operating conditions using oil as heat transfer fluid. Coatings are quite stable at temperatures of 400-450°C in vacuum without oxidation or diffusion problems and an operation life higher than 20 years is estimated considering the experience with older tubes and the new improvements in commercial tubes.

For evacuated tubes, typical thermal stability tests are performed in a high temperature oven under vacuum or an inert gas atmosphere at temperatures 100°C higher than operating temperature. Thermal degradation is assumed that follows Arrhenius law dependence [11] and tests performed at higher temperatures can be extrapolated to estimate life expectance in normal operating conditions.
For non-evacuated tubes, tests are performed in an oven in air, at temperatures 100°C higher than operating temperature. Absorber degradation in air, at high temperature, is mainly due to the oxidation of the metal reflector that increases thermal emittance and the oxidation of cermet metal particles that reduces solar absorptance. Molybdenum and tungsten, commonly used in the absorbers, are stable in vacuum at high temperatures, but they suffer oxidation in air. In this project, a new selective absorber has been developed with good optical properties that withstand 400°C in air without thermal degradation [12]. It has been tested in an oven in air, at 400°C, during 12 months.

7.3.4. Hydrogen diffusion

Although hydrogen diffusion through the tube is not an intrinsic absorber problem, it is related because diffusion barriers are applied under selective absorbers. It is very difficult to avoid hydrogen diffusion with a thin layer, but it can be reduced significantly with a dense layer of selected materials. Alumina (Al₂O₃), zirconia (ZrO₂) and other transition metal oxides are widely used as hydrogen diffusion barriers in microelectronics industry with promising results.

Rioglass introduced some years ago a diffusion barrier for hydrogen in the absorber deposition, prepared by a controlled oxidation of the stainless steel substrate that creates an oxide film that prevents hydrogen diffusion through the metallic tube and provide a more stable substrate for the sputtered absorber film.

7.3.5. Thermal stress

Thermal stress in selective absorber, induced by solar transitory or different solar concentration on receiver tube, can lead to coating cracking and peeling off. Typical way to simulate thermal stress is thermal cycling that consists of producing fast changes in sample temperature using a conventional oven or concentrated solar radiation with a solar furnace. Of course, it only can be used in absorbers for non-evacuated collectors.

7.4. Optical characterization

7.4.1. Solar absorptance

Solar absorptance can be calculated according the following equation:

\[
\alpha_s = \frac{\int_{0.3\mu m}^{2.5\mu m} \alpha_\lambda \ AM1.5D d\lambda}{\int_{0.3\mu m}^{2.5\mu m} AM1.5D d\lambda}
\]  

(4.8)

Where \( \alpha_\lambda \) is the absorptance for each wavelength value in solar spectrum and AM1.5D is the air mass 1.5 direct solar spectrum.

Taking into account that for opaque materials, absorptance plus reflectance \( R_\lambda \) is one (or 100%), then:

\[
\alpha_\lambda = 1 - R_\lambda
\]  

(4.9)
for each wavelength value in solar spectrum.

Selective absorbers are not perfect mirrors and some energy is reflected in other directions different than incident light angle, so it is required to use experimental hemispherical reflectance (every angle in the complete hemisphere) to calculate absorptance, so the following equation is obtained:

\[
\alpha_s = \frac{\int_{0.3 \, \mu m}^{2.5 \, \mu m} (1 - R_{\text{hem}}) \, AM \, 1.5 D \, d\lambda}{\int_{0.3 \, \mu m}^{2.5 \, \mu m} AM \, 1.5 D \, d\lambda}
\]  

(4.10)

Where AM 1.5D is solar spectrum Air Mass 1.5 (ASTM G173-03).

Hemispherical reflectance of the absorber tubes is measured with a double beam spectrophotometer with an integrating sphere coated with a highly diffusing material.

This spectrometer has two different measuring beams and the equipment makes a direct comparison between light reflected by the standard and the sample. Accuracy is very high and errors lower than 1% in solar absorption are obtained.

In order to reduce errors, a special sample holder is used to locate tube close to the measurement port in the integrating sphere. It is critical to achieve that measuring beam reaches tube completely and there are no beam losses outside the integrating sphere in port edges. Highest accuracy is obtained when measuring standard has tubular shape with the same diameter than absorber sample to be measured.

7.4.2. Thermal emittance

Thermal emittance is calculated in a similar way than solar absorptance using experimental hemispherical reflectance values in the solar and infrared region:

\[
\varepsilon_T = \frac{\int_{0.3 \, \mu m}^{2.5 \, \mu m} (1 - R_{\text{IR,hem}}) i_{\text{bb}} (\lambda, T) \, d\lambda}{\int_{0.3 \, \mu m}^{25 \, \mu m} i_{\text{bb}} (\lambda, T) \, d\lambda}
\]  

(4.11)

Where \( i_{\text{bb}} (\lambda, T) \) is the emission of a blackbody at the working temperature \( T \).

A Fourier Transform Infrared reflectance (FTIR) spectrophotometer, with a gold coated integrating sphere that has two measuring windows, one for the standard and the other for the sample, is used to measure hemispherical reflectance.

Fourier transform infrared spectrophotometers (FTIR) have only one measuring beam and it introduces some errors in reflectance measurements. In double beam spectrophotometers, like UV/VIS/NIR ones, reflecton from sample and references are compared at the same time in the integrating sphere. In a FTIR one, equipment records standard reflectance and then it records sample reflectance. This introduces an error, called substitution error, due to some light of the measuring beam, reflected in the sample, hits sample again after several reflections inside the sphere, before reaching the detector. So, obtained
reflectance is lower than real. Substitution error increases as sample infrared reflectance decreases and be as high as 4% of real value. Selective absorbers have low emissivity and error is between 1 and 2%.

Same considerations regarding sample holder and tubular standard shape, than in solar absorptance calculations, are required in thermal emittance calculations.

7.5. Glass cover and AR coating

7.5.1. Introduction

Glass cover is used in HCE to reduce convective thermal losses and to preserve selective absorber from outdoor exposition. It is a glass pipe, concentric to metallic absorber pipe and it needs to have high solar transmittance and a low thermal expansion coefficient to provide good thermal shock resistance, close to the thermal expansion coefficient of metallic absorber pipe at operating temperature, in order to reduce mismatch between both linear expansion coefficients. Vacuum is stablished in annulus between glass and metallic pipes to reduce thermal losses by conduction-convection and to avoid thermal oxidation of the selective absorber deposited on metallic pipe. This annulus is sealed with a glass-metal welding and a metallic bellow is used to compensate the mismatch expansion coefficient between glass and metal pipes.

Glass cover is produced using borosilicate glass that has a solar transmittance from 0.91 to 0.93, good thermal shock resistance and good outdoor durability. Most common borosilicate glasses used in solar receivers are:

- Borosilicate 5.1 (linear expansion coefficient of 5.1 x 10⁻⁶ /K) that presents alkaline earths and alumina in its composition. It has a solar transmittance about 0.92 and good chemical and mechanical properties to be employed in this application.
- Normal borosilicate 3.3 (linear expansion coefficient of 3.3 x 10⁻⁶ /K) without alkaline earths and alumina in its composition. It has a solar transmittance about 0.92, good chemical properties and the lowest thermal expansion coefficient that provides the highest thermal shock resistance. Its linear thermal expansion coefficient is lower, so it has better thermal shock resistance than 5.1 borosilicate glass, but elongation mismatch between glass and metallic pipes will be higher.

Glass jackets of receiver tubes are coated by a film on both sides (inner and outer) to reduce the reflection losses in the glass, increasing the optical efficiency of the receiver tube. This film is known as antireflective coating (ARC) and it has to satisfy two conditions (coating thickness dc, and refractive index value nc) to obtain the destructive interference of light which is reflected at the glass-coating interface and at the coating-air interface. These values come from solving the Fresnel’s law equations for normal incidence and for a determined wavelength. The wavelength value selected is usually around 600nm for solar applications, as this wavelength value is centered in the maximum irradiance zone of solar spectrum. In this way, the optimal ARC must have a thickness around 150 nm and a refractive index value of 1.22.

The material most widely used as ARC on glass is silicon dioxide (SiO₂) and the low refractive index value is achieved by introducing porosity in the coating. This porous nature, necessary to increase the glass transmittance, is the weak spot of this material in terms of durability. These pores easily absorb water and other volatile organic components, increasing the refractive index of the coating and lowering the
transmittance. This process, mostly reversible, is known as “breathing of the coating” [13]. Another consequence of the porous structure is the weak mechanical performance coming from the weak binding force between the silica particles and substrate as well as between the particles [14].

#### 7.5.2. Aging and durability

Antireflective coatings are composed of porous silica and they present a high chemical stability, good UV radiation behavior and a low abrasion resistance. Main accelerated aging tests performed on ARC are:

* Abrasion test*. It is based on the international standard IEC 62862-3-3 draft part 4.6.2 and consists of repeating dry rubbing (in lengthwise cycles) on the AR coated samples with the abrasive material. Normally, a TABER linear abraser is used to perform these tests. It is a qualitative test that do not has a correlation with real outdoor exposition and it only gives information to compare mechanical resistance of different ARC used by producers.

* Damp Heat Test IEC 62108, Test 10.7*. Samples are tested at a temperature of 85ºC and a humidity of 85% during 1000h. Materials pass the test if solar transmittance loss is lower than 1%.

* Condensation resistance test*. It is performed according to ISO 6270-2, exposing samples to constant conditions of 40 ºC with 100 % relative humidity in the dark. Samples are subjected to these conditions for 480 hours. Materials pass the test if solar transmittance loss is lower than 1%. All these tests are qualitative and, if a material passes all the tests, it does not imply that its durability in field conditions will be good enough. It is necessary to consider that durability will depend of dust particle composition and size, wind direction and intensity, contaminants and cleaning frequency and conditions.

#### 7.6. Glass cover cleaning

During operation, Absorber tubes are exposed to outdoor conditions and soiling is produced. Dust particles on glass surface produce a decrease in solar transmittance and a dispersion of solar radiation that implies that some sunlight that crosses glass cover does not reach solar absorber. When soiling is strong, solar transmittance losses can be as high as 6-7%, so glass covers cleaning results critical to assure power plant performance.

Cleaning is usually performed with pressurized water projected on glass tube to remove soiling. During cleaning, particles deposited on glass surface produce abrasion on the outer layer of the ARC and some solar transmittance is lost with cleaning. There are some controversial in how often is necessary to clean HCE glass to remove soiling, considering ARC damage produced. ARC increases solar transmittance around 5%, so outer antireflective layer contributes with 2.5% to average transmittance. So, it has no sense to reduce cleaning frequency to avoid losing 2.5% in transmittance (outer AR layer removal) when heavy soiling implies a transmittance lose much higher.

#### 7.6.1. Optical characterization

Main optical parameter that defines an ARC is solar transmittance, the average material transmittance in solar spectrum. Spectral transmittance $\tau(\lambda)$ can be measured directly with the spectrophotometer, locating sample to be measured between light source and detector. Solar transmittance can be calculated using experimental spectral transmittance values, according the following equation:
where AM1.5D is the air mass 1.5 direct solar spectrum (ASTM G173-03).

Transmittance of the glass cover is measured with a double beam spectrophotometer, locating the sample at the opening of the integrating sphere. It is not possible to measure the transmittance of the complete tube and it is necessary to cut the tube to measure only one tube section.

### 7.7. Glass to metal seal and bellows for evacuated pipes

The glass cover is connected to the steel pipe using metallic expansion bellows to compensate different linear thermal expansion of glass and steel, when solar receiver is working at nominal temperature. The glass to metal welding is used to connect the glass cover and the flexible bellows and it is shielded from concentrated solar radiation to avoid the thermal and mechanical stress that could affect welding performance and durability.

One of the problems related to constructing glass to metal seals lies in the fact that metals generally have a linear thermal expansion coefficient considerably greater than typical borosilicate glasses and this leads to the establishment, in the constructed joint, of mechanical stresses which can easily lead, during thermal heating to which the joint is subjected both in the step of manufacturing and using the collector, to breaking the joint.

In order to solve the problem of mechanical stresses in the seal, there are several approaches:

- Alloys having a value of coefficient of linear thermal expansion very close to that of the glass such as Kovar® that has extensively been employed to make glass to metal seals [15].
- SS AISI 430 which has an intermediate value between 3.3 borosilicate glass and AISI 321 SS [16], [17].
- Housekeeper method in which AISI 321 stainless steel is welded directly to borosilicate 3.3 glass tube [18].

Another factor observed in HCE initial generations, which produced receiver tubes failure, is concentrated solar radiation that reaches directly the bellow, especially during low-sun-angle operating conditions [19], and glass-metal welding that induces thermal stresses in the welding producing glass-metal welding failures. So, efficient internal and external shields needs to be employed to completely cover bellows and glass-metal welding from solar concentrated radiation.

Metallic bellows used to compensate different linear expansion coefficient of glass envelope and metallic absorber tube. Depending on the specific receiver design, the bellow might also have to support the weight of the glass envelope.

Main degradation problems observed in metallic bellows is due to the process known as intergranular stress corrosion cracking (ISSC). So, recommended materials for bellows are stainless steels stabilized.
with titanium (Grade 321) or niobium (Grade 347) that are less susceptible to suffer ISCC than lower grade 304 and 316 stainless steels.
8. References


Chapter 5: D6.8 Best practice on Evaluating Steel Corrosion in Molten Salt Environment

1. Scope and objective

The main goal of this deliverable is to unite the best practice learnt and applied along RAISELIFE project regarding the evaluation of steels in molten salt environments. This document aims to complement the Testing protocol defined in month 6 of the project in the frame WP4.
2. **Normative references**

Best practice in evaluation of steels in molten salts aims to complement the testing protocol defined in the frame of WP4, which is based on the following standards:

- ISO 8407 Corrosion of metals and alloys - Removal of corrosion products from corrosion test specimens.
- ISO 17245:2015 Corrosion of metals and alloys - Test method for high temperature corrosion testing of metallic materials by immersing in molten salt or other liquids under static conditions.
3. Methodology and approach

In the frame of RAISELIFE project, different coated and uncoated steels have been studied taking into account their corrosion resistant behavior against molten salt environment. Depending on the area of the industrial plant considered, molten salts are exposed to different conditions, being their flowing status and temperature the most important. Best practice must assure that testing protocol covers all the conditions that the steel candidates will suffer when implemented in plant.

<table>
<thead>
<tr>
<th>Test type</th>
<th>Molten salt conditions</th>
<th>Plant area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Static</td>
<td>Static. Isothermal.</td>
<td>Molten salt storage tanks</td>
</tr>
<tr>
<td>Cyclic</td>
<td>Static. Cooling and heating ramps.</td>
<td>Cold tank – Receiver – Hot Tank</td>
</tr>
</tbody>
</table>

The methodology for this document elaboration has been to divide the corrosion test in different points where important best practices have been detected:

- Sample preparation
- Test conditions
- Preparing and cleaning
- Gravimetric analysis
- Metallographic examination

Points covered above are present in the three type of test considered. Best practices specifically detected in any of the test will be specified in the defined points.
4. **Best practice specifying admissible impurity levels in the molten salts mixture**

Apart from oxidizing species such as NO$_2^-$ and NO$_3^-$ and O$_2$ [1], commercial salts contain levels of impurities such as carbonates, nitrites, chlorides, and sulphates that induce even more corrosion [2, 3]. Therefore, great care should be taken of the level of impurities in the system. Among these impurities, chlorides and sulphates affect the corrosive behavior of the salts significantly [4-6]. Moreover, the impurity level may affect the thermal properties of the salt mixtures (e.g. melting and freezing points, and degradation temperature). However, the use of low-purity salts is often associated with higher prices; that is why at industrial scale and for obvious economic reasons, it is interesting to use high-purity salts. Therefore, it is of great importance to strike a balance between purity and corrosiveness of the salt, taking into account both thermal properties and the industrially important economical aspect.

In the light of the above, a characterization protocol should be followed in order to specify the admissible level of impurities in molten salt mixtures, considering the corrosive effect and the physicochemical properties of the salts, without forgetting the important role of the price. Given that a key challenge and difficulty has been the lack of experience in the stakeholder community on best practice in evaluating and specifying the maximum admissible impurity level, the best practice on this matter is detailed in the following sections.

4.1. **Corrosive effect of the salt mixtures**

4.1.1. **Analysis of the corrosive behavior of the salt**

The analysis of the corrosive effect of the salts should be performed in an electrical chamber furnace with specimens of a reference material placed in alumina crucibles and fully immersed in the salt mixture to give a melt depth of about 3.5 cm. The temperature to be fixed should be selected on the basis of the specific requirements, being recommended the selection of the maximum temperature at which the salt will work.

The minimum duration of corrosion tests recommended is 1000 h, this allowing the operator to appreciate significant changes on the reference material for evaluation; however, longer times would deliver more realistic results. In addition, it is recommended to analyse the reference material in contact with the salt via gravimetric at intermediate times (e.g. at 24, 72, 168, 250, 500, 750, 1000 hours). To this end, at least three samples of this material should be removed, rinsed, dried and weighted at each selected time, following the above-described protocol and good practices for evaluating corrosion in molten salt environments.

Once weighted, the previously tested specimens should be characterized by appropriate techniques, such as Scanning Electron Microscopy – Energy Dispersive X-Ray Spectroscopy (SEM-EDX) and X-Ray Diffraction (XRD).

This analysis should be ideally performed with both a high-purity salt that will be used as reference, and the salt under analysis.

4.1.2. **Admissible corrosive effect of the salt**

Once performed the tests and obtained the corresponding results, results obtained with the salt mixture under analysis should be compared to those obtained with the high-purity salt use as reference. That is, it
is necessary to compare both the gravimetric (weight gain or loss) and the microstructural results (mainly the thickness of the corrosion layer and corrosion products).

According to the experience gained in RAISELIFE, the weight changes from which the salt is considered too much corrosive in comparison with the reference salt have been 3 mg·cm\(^{-2}\), using Solar Salt and T91 ferritic-martensitic steel as references.

On the other hand, and according to the experience throughout the project, the corrosion layer thickness should be considered as discriminatory parameter in case of compact and adherent layers. This is not the case of T91, where the corrosion products are detached during the whole experiment.

4.2. Thermal properties of the salt mixture

4.2.1. Analysis of the thermal properties of the salt

With the aim of evaluating the effect of the level of impurities on the thermal properties of the binary salt mixture, at least melting point, freezing point and degradation temperature should be determined. As previously described, a high-purity salt mixture should be used as reference.

Melting and freezing points need to be determined by differential scanning calorimetry (DSC), while thermal stability will be measured by thermogravimetric analysis (TGA). The crucibles used in the DSC should be preferably made of aluminium and hermetically sealed, whereas the crucibles used in the TGA should be made of platinum. Both tests should be preferably conducted under a flowing inert nitrogen atmosphere of 50 ml·m\(^{-1}\) and at a heating rate of 10 °C·min\(^{-1}\), using in each case a sample mass of approximately 10 mg. It is important to calibrate the equipment before each analysis in order to avoid wrong measurements.

4.2.2. Admissible values for thermal properties of the salt

According to the experience gained in RAISELIFE, the admissible variations in the values of the thermal properties, specifically in melting, freezing and degradation temperature, are fixed in 4%; situations in which the freezing and melting points decrease and/or the degradation temperature increases are not considered in this percentages, since this variations are positively viewed.

4.3. Admissible impurity level for Solar Salt

According to the experimentation performed and results achieved throughout the project, the maximum impurity level that allows a suitable work with Solar Salt consists of 500 ppm Cl\(^{-}\) and 500 ppm SO\(_4\)\(^{2-}\). These concentrations of chlorides and sulphates seem to be more interesting, both from corrosive and from economic point of view. Moreover, this impurity level only reduce the working-temperature range in 4 °C, when set against a high-purity Solar Salt (133 ppm Cl\(^{-}\) / 59.2 ppm SO\(_4\)\(^{2-}\)).
5. Evaluation of steel corrosion in molten salt environments

5.1. Sample preparation

The test samples are prepared in the form of a rectangular plate, a disc or a cylinder. They are machined to remove the strata affected by cutting and the final surface finishing of the test pieces is obtained by polishing with SiC abrasive papers.

The sample dimensions are measured with a calibre with a precision of ±0.02 mm. Three dimensions in three different positions are taken. After ultrasonically degreasing in isopropanol or ethanol, the samples are dried with hot air or left in a desiccator. The mass of the samples is determined prior to exposure. At least two measurements are made for each sample with a difference between the measurements not exceeding 0.05 mg.

5.2. Test conditions

5.3. Preparing and cleaning after test

The test pieces are removed from the furnace at different time intervals. At the end of the test, the samples are removed from the crucible and left under laboratory air to cool down. Then, the samples are placed in hot distilled water (≈ 80 °C) to remove salt residues because nitrates are soluble in hot water and, finally, they are dried to be weighted.

5.4. Gravimetric analysis

Gravimetric analysis allows the determination of corrosion kinetics of the tested samples. To do that, it is necessary to:

- Weight and measure the samples prior to exposure (in all their dimensions).
- Weight at the end of test.

A large weight loss usually indicates significant corrosive attack [7], but it is difficult to distinguish if it is that caused by dissolution and/or by spallation of scales. An important weight gain would be generally associated with oxidation and formation of oxide scales [7]. But, a small weight change do not necessarily mean that the material is resistant to corrosion because if both dissolution and oxidation occur at a similar rates the final weight change would be small even if the corrosion was significant.

For uncoated steels, the samples shall be descaled after test to determine the mass loss and calculate corrosion kinetic because oxide formation, dissolution and spallation can occur and lead to a misunderstanding of the net mass change. For this, the corrosion products are removed from test samples by applying an adequate chemical etching without affecting the substrate integrity according to standard ISO 8407. After descaling, the samples can be analysed by XRD to verify that all oxide residues have been removed. For coated steels, the samples are not descaled after test because the chemical etching could affect the coating.

The corrosion rate can be then calculated using the following equations:

\[ \frac{\Delta m}{S_0} = \frac{m_i - m_f}{S_0} \]  
\[ \left(\frac{\Delta m}{S_0}\right)^2 = k_p t \]
Where \( m_i \) and \( m_f \) are the initial and final weights respectively, \( \Delta m \) the metal loss, \( S_0 \) the initial metallic surface, \( k_p \) the parabolic constant and the time.

The corrosion rate will determine if it is advisable to use it for the activity studied and depend on each steel and coating used. For each steel there is a recommendation for use according to the corrosion rate, based on experience and knowledge of the engineers.

5.5. Metallographic examination

Metallographic examination consists of analysing the surface and cross-section of the sample following the procedures provided in standard ISO 26146.

**Uncoated steels**

Uncoated steels are examined to determine if they have been affected by corrosion under these conditions. The following aspects are mainly evaluated.

- Formation of oxide layers. If an oxide has been formed, its composition is determined as well as the thickness and if it can act as a protective barrier against corrosion. Corrosion products should be identified by X-ray diffraction analysis.
- Internal attack of the substrate.
- Material losses.

To be able to consider that steel behaves well under these conditions, it should be metallographically analyzed to identify evidence or extent of degradation and not be significantly affected and if an oxide has formed, it must be protective and stable.

**Coated steels**

Coated steel samples are examined after the test and compared with the uncoated steel after the same duration. In order to determine the effectiveness of the coating, the following aspects are mainly evaluated:

- Coating spallation;
- Thickness of the coating after the test;
- Interdiffusion between coating-substrate;
- Changes in the microstructure and composition;
- Attack of substrate or coating;
- Presence of defects, cracks, etc.;
- Formation of oxides and, if applicable, if they are protective.

If the coated steel does not suffer significant changes after the test, this coating can be considered as a possible high temperature corrosion resistant coating in molten salt for this steel.

**Welded joint**

Many parts are welded in a plant and these areas have to be specially analysed because they are preferred sites for corrosion. It is necessary to observe if there are changes in the substrate or defects, if the Heat-Affected Zone (HAZ) was degraded, and in which extent.
6. Case studies

6.1. Case 1: Effect of the impurity level on uncoated T91 ferritic-martensitic steel

Conditions
Exposure of uncoated substrates to standard grade solar salt (60wt% NaNO₃ - 40wt% KNO₃), containing previously set impurity levels

Material of construction
Tubes (flat ground samples) of UNS K90901 or T91 (9% Cr).

Exposure conditions
Up to 1,000 h exposure in molten salts at 560°C. Four impurity levels: (i) 133 ppm Cl⁻ / 59.2 ppm SO₄²⁻ (used as reference); (ii) 300 ppm Cl⁻ / 300 ppm SO₄²⁻; (iii) 500 ppm Cl⁻ / 500 ppm SO₄²⁻; and (iv) 700 ppm Cl⁻ / 700 ppm SO₄²⁻.

Examination and results
After 1,000 h exposure, T91 ground specimen forms a multilayer structure formed by iron oxides on the outer layers and iron chromium spinel in the inner layers, and thus prone to suffer spallation, with a thickness that, generally, is increased when increasing the impurity level (Figure 5.1).

![Figure 5.1: Evolution of the oxide scale formed T91 with ground surface (1200 SiC) after 1000 h of exposure to Solar Salt at 580°C: (a) reference impurity level; (b) 300 ppm; (c) 500 ppm; and (d) 700 ppm.](image-url)
XRD analysis of the samples reveals the presence of Fe$_2$O$_3$ and Fe$_3$O$_4$, which according to the SEM-EDX analysis corresponds to the outer corrosion layers, while FeCr$_2$O$_4$ is the corrosion product formed in the inner layer (Figure 5). By comparing the XRD results, it was observed that better-defined peaks of corrosion products appeared when increasing the level of impurities.

Figure 5.2: X-ray diffraction patterns of reference material at the end of test (a) reference impurity level; (b) 300 ppm; (c) 500 ppm; and (d) 700 ppm.

Cause and its explanation

The higher the impurity level, the higher and better-defined the peaks are determined, which is due to the thicker corrosion layer observed.
**Solutions and recommendations**

An increase on the impurity level of the corrosion media might lead to an increase of its corrosiveness. Therefore, in case of highly impure salt mixtures the use of protective coatings or the use of high-alloyed steels such as Ni-based alloys (e.g. Haynes 230) is recommended.

### 6.2. Case 2: Effect of the impurity level on thermal properties of Solar Salt

#### Conditions

Exposure of standard grade solar salt (60wt% NaNO$_3$ - 40wt% KNO$_3$), containing previously set impurity levels.

#### Material and equipment

Melting and freezing points of the prepared binary salts are determined by differential scanning calorimetry (DSC), while thermal stability is measured by thermogravimetric analysis (TGA). Prior to the analyses, both instruments are calibrated with indium.

#### Exposure conditions

Both tests are conducted under a flowing inert nitrogen atmosphere of 50 ml·m$^{-1}$ and at a heating rate of 10 °C·min$^{-1}$. The typical sample mass used in each test was 10 mg.

#### Examination and results

After testing and as shown in Table 5.2, melting point, freezing point and degradation temperature are determined.

<table>
<thead>
<tr>
<th>Impurity content, ppm</th>
<th>Melting point, °C</th>
<th>Freezing point, °C</th>
<th>Degradation temperature, °C</th>
<th>Viscosity, cP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cl$^-$</td>
<td>SO$_4^{2-}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>131</td>
<td>59.2</td>
<td>227</td>
<td>235</td>
<td>539</td>
</tr>
<tr>
<td>300</td>
<td>300</td>
<td>226</td>
<td>221</td>
<td>529</td>
</tr>
<tr>
<td>500</td>
<td>500</td>
<td>226</td>
<td>219</td>
<td>519</td>
</tr>
<tr>
<td>700</td>
<td>700</td>
<td>226</td>
<td>218</td>
<td>515</td>
</tr>
</tbody>
</table>

#### Cause and its explanation

The melting point does not appear to be influenced by the level of impurities, this being similar in the four salts (~226 °C). On the other hand, the freezing point of the salt does not seem to be affected by the lower impurity levels, i.e. until reaching 500 ppm of each impurity (~220 °C). However, when the impurity level is enhanced until 700 ppm of Cl$^-$ and 700 ppm of SO$_4^{2-}$, the freezing temperature is rising by approximately 15 °C (~235 °C). This parameter is of great importance, since it limits the operational temperature at low temperatures. Regarding the upper temperature limit, it is observed the reduction in the degradation temperatures when increasing the level of impurities. According to the results, degradation temperature falls down to 515.44 °C when the concentration of Cl$^-$ and SO$_4^{2-}$ reaches 700 ppm.
Solutions and recommendations

Given the impact of the impurity level on thermal properties of Solar Salt, it is highly recommended not to work over an impurity level of 500 ppm Cl\(^{-}\) and 500 ppm SO\(_4\)\(^{2-}\).
7. References


Chapter 6: D6.9 Best practice on Steel Selection for CSP

1. Scope and objective

The objective of this document is to help on the selection of metallic construction materials for concentrated solar power (CSP) plants. The CSP technology is seen as one of the most potential source for electricity production with a strong impact on the energy mix production of countries and regions characterized by strong sunshine and clear skies. Nevertheless, it is still possible to draw some similarity between CSP and the traditional coal-fired thermal power plants. Based on the long-time experience in coal-fired thermal power plants on the market, some steel grades like T/P91 or VM12-SHC are already recognized for their good creep rupture strength and oxidation properties at temperatures up to 600°C-650°C. The lack of knowledge on their behavior in contact with molten salt is compensated thanks to the corrosion experiments performed in different laboratories within the frame of the RAISELIFE project.

The use of molten salts as heat transfer fluid in solar power plants asks for receiver tubes operating at higher temperature (approximately 700°C, metal temperature) and lower pressure (around 15 bar), in comparison to tubular exchange components, such as superheater and reheater in coal-fired thermal power plants (maximum operating metal temperature: 650°C and steam pressure: approximately 280 bar). Based on this simple comparison, the common steel grades found in coal-fired thermal power plants are not sufficient as tubular solution for the high temperature section of the solar receiver. Thus, other solutions such as advanced stainless steels and nickel based alloys are considered the most promising candidates for CSP construction receiver tubes due their higher performance at the considered high operation temperatures as well as their higher corrosion resistance in molten nitrates.

However, such advanced stainless steels and nickel based alloys might have an overall impact on the construction plant due to their both higher pre-material and production costs. An alternative derived from these costs is the use of significantly cheapest commercially available ferritic-martensitic steels. These substrates can be easily coated to protect them from the very aggressive molten salts. Therefore, an important aspect within this document is the economical assessment of degradation of the foreseen steel tubes - compared with coated and uncoated ferritic-martensitic steels - and the accelerated ageing solar and environmental test results. The contribution of each one will help on the decision making of materials selection for improving durability and lifetime of CSP systems.
2. **Normative references**

The Normative documents provide the guidelines, in general terms, and more specifically are related to Standards, (internal) technical specifications and/or codes of best practices (see list below).

<table>
<thead>
<tr>
<th>Type of test</th>
<th>Document title</th>
<th>Document ID</th>
<th>Type of document</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1.- Corrosion tests in molten salts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.1. - Corrosion tests in molten salts</td>
<td>Corrosion of metals and alloys - Test method for high temperature corrosion testing of metallic materials by immersing in molten salt or other liquids under static conditions</td>
<td>ISO 17245</td>
<td>DIN ISO Standard</td>
<td>2015</td>
</tr>
<tr>
<td>1.2.- Thermo-cyclic exposures</td>
<td>Corrosion of metals and alloys - Test method for thermal-cycling exposure testing under high-temperature corrosion conditions for metallic materials</td>
<td>ISO 13573</td>
<td>DIN ISO Standard</td>
<td>2012</td>
</tr>
<tr>
<td>1.5.- Metallographic sample preparation</td>
<td>Standard guide for preparation of metallographic specimens</td>
<td>ASTM E3-11</td>
<td>ASTM Standard</td>
<td>2017</td>
</tr>
<tr>
<td><strong>2.- Accelerated aging environmental tests</strong></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>2.1.- Damp Heat Test</td>
<td>Concentrator photovoltaic (CPV) modules and assemblies - Design qualification and type approval</td>
<td>IEC 62108 Test 10.7b</td>
<td>IEC standard</td>
<td>2016</td>
</tr>
<tr>
<td>2.2.- Humidity Freeze Test</td>
<td>Concentrator photovoltaic (CPV) modules and assemblies - Design qualification and type approval</td>
<td>IEC 62108 Test 10.8</td>
<td>IEC standard</td>
<td>2016</td>
</tr>
<tr>
<td>2.3.- Neutral Salt Spray Test</td>
<td>Corrosion tests in artificial atmospheres - Salt spray tests</td>
<td>ISO 9227</td>
<td>ISO Standard</td>
<td>2017</td>
</tr>
<tr>
<td>2.5.- Tape peel adhesion test</td>
<td>Self adhesive tapes - Determination of peel adhesion properties</td>
<td>DIN EN ISO 29862</td>
<td>ISO Standard</td>
<td>2018</td>
</tr>
<tr>
<td>Section</td>
<td>Description</td>
<td>Standard / Method</td>
<td>Year</td>
<td></td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
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<td></td>
</tr>
<tr>
<td>3.3.</td>
<td>Creep and stress rupture testing</td>
<td>Use of Thermocouples in Creep and Stress Rupture Testing to 1800 °F (1000°C) in Air</td>
<td>ASTM E633, ASTM Standard 2013</td>
<td></td>
</tr>
<tr>
<td>3.5.</td>
<td>Slow Strain Rate Tensile Test (SSRT)</td>
<td>Standard Practice for Slow Strain Rate Testing to Evaluate the Susceptibility of Metallic Materials to Environmentally Assisted Cracking</td>
<td>ASTM G129 - 00, ASTM Standard 2013</td>
<td></td>
</tr>
</tbody>
</table>
3. **Methodology and approach**

In general, in order to select a steel or a group of materials to be used as metallic construction material for a defined application, a number of factors has to be previously defined. These factors involve all those possible parameters under which the specified component will operate based on the designed service conditions. The reason for that is to be able to define and to evaluate the appropriate lifetime of the component under which it should operate in a safely manner. As for the case of coal-fired power plants, CSP systems must comply with the requirements set up by the Pressure Equipment Directives (PED), even though the operation pressure is lower in comparison to coal-fired power plants. In addition, the use of determined materials is restricted to certain temperature ranges, based on the evaluation of (basically) the mechanical properties of such materials. Therefore, it is of great importance for the material’s selection to review the existing ASME Code Case (CC) for the considered grades. The maximum application temperature provided in the CC documentation must serve, at a first instance, for the first filter on the material’s selection.

Some of the main requirements are,

- Evaluation of the product (and heat) chemical composition.
- Determination of the mechanical properties (tensile test, Vickers hardness and Charpy impact toughness) at room temperature and in the expected temperature range of operation and (tensile tests and Charpy impact toughness). Low cycle fatigue, and if required thermo-mechanical fatigue, should be provided for critical components working under fatigue relevant conditions. The test methods shall be as given in ASTM A370, ASTM A1058, ASTM E8, ASTM E21, or other equivalent national or international test standards.
- Determination of relevant physical properties. Test methods shall be as follows: ASTM E228 or ASTM E831 for thermal expansion coefficients; ASTM C177 for thermal conductivity and thermal diffusivity; ASTM E1875 for modulus of elasticity; ASTM E1875 or ASTM E132 for Poisson’s ratio. Further physical property values might be also required.
- Evaluation of the long-term creep behavior. These values can be found in the VdTÜV datasheet and in the ASME CC. Further evaluation of grades is done within the ECCC (European Creep Collaborative Committee) working group.
- Corrosion resistance in the prevailing media. Although this requirement is not included in any material’s datasheet, Directive, Norm nor CC, in the later years the material’s corrosion behavior is gaining more importance. This is related to the fact that the newly steel developments focused on achieving higher creep rupture behavior. Nowadays the spotlight is shifted towards the study of the corrosion resistance of the materials under (simulated or real) service conditions, which actually might be the determining criteria affecting the lifetime of the component - and not the creep behavior - and thus deciding whether a material is selected as potential candidate for the specified component or not.

The plant’s designers/operators should identify the following aspects related to the specific material,

- Dimensions and tolerances, including final surface processing.
- Chemical composition and relevant mechanical properties as considered in the specification(s).
- Operation parameters: pressure, stresses in the component (internal/external), temperature and media, differences in metal temperature (cycling). For instance, cyclic loading is not included in any specification and it is not enough considered, even though it might substantially affect the lifetime expectation of the component as such.

- Definition of the expected lifetime of the component, as the material has been selected. This is an important task for plant’s designers.

- Determination of the corrosion allowance (CA) based on the existing corrosion tests (simulated laboratory conditions, field conditions, other relevant data sources).

- Based on the material’s selection, the adequate welding filler material should be used following the corresponding documentation (VdTÜV datasheet, ASME CC, etc). The welding of such components should be done following the welding procedure specification (WPS). Welding can just be done by expert/skilled/qualified welders.

In case a protective coating is applied on the surface of selected tube/pipe material, the material’s substrate is still subjected to the main requirements provided above. Any degradation of the material’s properties - as function of time/temperature - as consequence of the application of a coating, has to be properly reported to all parties. Data on coated specimens that it should be provided are, long-term creep behavior, welding effect, mechanical properties, etc.

At the beginning of the Raiselife project, several candidate materials were chosen in order to assess their candidacy as metallic construction component as receiver tube materials. The project partners selected several ferritic-martensitic steels, T22 (2.5 wt% Cr), T91 (9 wt% Cr) and VM12-SHC (12 wt% Cr) (Chromium nominal chemical compositions). The Nickel based IN617 alloy was selected due to its expected higher corrosion resistance in molten salts. Recently, another Nickel based alloy, Haynes 230 alloy (UNS N06230), has also been included in the test matrix as this material is seen as a potential candidate to be used as receiver tube.

In order to establish the corrosion resistance of the proposed materials, corrosion resistance tests in molten salts were performed at different conditions, including various testing temperatures within the range 560°C-600°C and times and different salt compositions (with and without chloride and sulphate impurities) to be able to rank these materials. These tests were performed by partners involved in the WP4 (DFI, INTA, Fraunhofer and UCM).

To get a complete overview on the selection of the materials, the impact of the economical assessment of degradation of steel tubes studied within the WP5 and the accelerated ageing solar and environmental test results obtained from WP3 should be used to complement the material’s behavior from the results obtained from WP4.

### 3.1. Corrosion behavior

The guideline for best practices for material selection and testing based on isothermal (discontinuous) and cyclic corrosion testing is shown in the table below. These tests are representative of the material’s behavior under real molten salt conditions and thus will provide a benchmark between materials and it can be used for the determination of the component’s lifetime in terms of corrosion degradation (in terms of CA) when exposed to high temperature corrosion in molten salts. The table below gives a full description of the main parameters recommended to perform different kind of corrosion tests.

**Table 6.2: The main parameters recommended to perform different corrosion tests.**
<table>
<thead>
<tr>
<th>Experimental parameters</th>
<th>Isothermal (Discontinuous) tests</th>
<th>Cyclic tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of furnace (3-heating zone, ...)</td>
<td>Muffle furnace</td>
<td>Muffle furnace</td>
</tr>
<tr>
<td>Type of reaction tube (sinter Al₂O₃, Quartz, ...)</td>
<td>Horizontal furnace (3-Zones)</td>
<td>---</td>
</tr>
<tr>
<td>Reaction tube diameter (in mm)</td>
<td>Quartz</td>
<td>---</td>
</tr>
<tr>
<td>Samples placed in alumina crucibles (Y/N)</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Purging method</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Testing Atmosphere</td>
<td>Laboratory air (static)</td>
<td>Laboratory air (static)</td>
</tr>
<tr>
<td></td>
<td>Laboratory air (flowing 4 L/h)</td>
<td></td>
</tr>
<tr>
<td>Exposure temperature (°C)</td>
<td>560-600</td>
<td>Max. 580 °C</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Min. 300 °C</td>
</tr>
<tr>
<td>Total flow rate (cm/s; l/h)</td>
<td>Muffle: static</td>
<td>Muffle: static</td>
</tr>
<tr>
<td></td>
<td>Horizontal: X cm/s; 4 l/h</td>
<td></td>
</tr>
<tr>
<td>Heating rate(s) (in °C/min)</td>
<td>10°C/min (up to 230°C)</td>
<td>25 °C/min</td>
</tr>
<tr>
<td></td>
<td>2°C/min (up to 290°C)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>10°C/min (up to target temperature)</td>
<td></td>
</tr>
<tr>
<td>Cooling rate(s) (in °C/min)</td>
<td>Muffle: cooling in air</td>
<td>10°C/min (between 580°C - 500°C)</td>
</tr>
<tr>
<td></td>
<td>Horizontal: furnace cooling</td>
<td>6°C/min (between 500°C - 400°C)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4°C/min (between 400°C - 300°C)</td>
</tr>
<tr>
<td>Specimens taken from (tube, pipe, plates, ...)</td>
<td>Tubes</td>
<td>Tubes</td>
</tr>
<tr>
<td>Grinding/polishing/method (by hand, machine, ...) before exposure</td>
<td>Grinding with P180 (only uncoated substrates)</td>
<td>Grindng with P180 (only uncoated substrates)</td>
</tr>
<tr>
<td></td>
<td>Progressive grinding with SiC paper down to P4000</td>
<td></td>
</tr>
<tr>
<td>Polishing paper (incl. previous to final) before exposure</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td></td>
<td>3 µm and 1 µm using diamond suspensions</td>
<td></td>
</tr>
<tr>
<td>For coating applications-Final surface finishing</td>
<td>Ultrasound and paper wiping to remove the bisque Glass-bead blasted</td>
<td>Ultrasound and paper wiping to remove the bisque Glass-bead blasted</td>
</tr>
<tr>
<td>Samples dimension (in mm) (other dimensions are also possible)</td>
<td>20x10x3</td>
<td>20x10x3</td>
</tr>
<tr>
<td>Max. No. of specimens in one test (incl. how many specs. for reproducibility proposes)</td>
<td>Muffle: 1 spec./crucible (max. 24 crucibles)</td>
<td>Muffle: 1 spec./crucible (max. 24 crucibles)</td>
</tr>
<tr>
<td></td>
<td>Horizontal: 1 spec./crucible (a total of 18 crucibles)</td>
<td></td>
</tr>
<tr>
<td>The specimens are (lying, hanging, within crucibles, ...) in the furnace</td>
<td>Inclined inside individual crucible Individual crucibles</td>
<td>Inclined inside individual crucible Individual crucibles</td>
</tr>
<tr>
<td>Molten salts composition</td>
<td>NaNO₃-KNO₃ (60wt%-40wt%) (w/wo impurities: NaCl, Na₂SO₄)</td>
<td>NaNO₃-KNO₃ (60wt%-40wt%) (w/wo impurities: NaCl, Na₂SO₄)</td>
</tr>
<tr>
<td>Salt replenishment</td>
<td>Yes, every time interval</td>
<td>Yes, every time interval</td>
</tr>
<tr>
<td>Interruptions for weighting</td>
<td>Samples are removed after different time intervals and weighted depending on the specific test. Every 100h, 300h, 1000h</td>
<td>Samples are removed after different time intervals and weighted depending on the specific test.</td>
</tr>
<tr>
<td>Rinsing of samples in warm distilled</td>
<td>Y</td>
<td>Y</td>
</tr>
</tbody>
</table>
To get better understanding of the corrosion behavior of the selected materials under conditions similar to service, dynamic corrosion tests were performed using a constant flow of a preferred molten salt composition. The overview of the guidelines to carry out these tests is given in Section 4.2.3 of the Deliverable D4.7 document.

The results coming from these tests must be relevant for all parties, plant designers, plant operators and tube/pipe producers. This information should be delivered in terms of corrosion loss (i.e. wall thickness loss) in units of μm/year or in form of oxidation rate constant (kp, in μm²/h). In this form, all kind of materials can be compared based on their corrosion allowance (CA). The determination and lifetime predictions must be evaluated according to the procedure described in DIN ISO 21608:2012. To determine wall thickness loss, uncoated samples must be descaled by chemical etching to remove corrosion products and oxides according to DIN EN ISO 8407:2014-06, so that the metal loss could be measured to estimate the thickness loss.

After certain operation intervals, the evaluation of the material’s state has to be performed in order to determine the remaining lifetime of the component and to avoid any risk during operation. This task should be a part of the O&M best practices (D6.5). This evaluation can be realized based on the component itself, where possible, e.g. destructive methods can be used to determine the wall thickness loss. Otherwise, non-destructive methods shall be considered. Online corrosion monitoring seems to be the best way to follow up the material’s behavior providing an online reading of the CA values.

Any change on the material’s microstructure during operation (e.g. formation of creep voids) shall be reported and the corresponding remaining lifetime, for the dedicated component, shall be evaluated.

3.2. Accelerated ageing solar and environmental test

Solar and environmental accelerated tests should be considered as they might provide very valuable information in rather short testing time. These tests, will allow the manufacturers to improve the quality of their products and thus the required performance. In addition, accelerated tests will provide a direct comparison between the various materials under the prevailing testing conditions, allowing a benchmark on the material’s selection in a quick manner. Even though the target of these tests is to promptly provide results, they have to represent those conditions that would be found in the field during service. The final target of these sorts of tests is the development of lifetime prediction models based on short-term testing. The selection of the main testing parameters should be well defined in advanced, by including those predominant parameters relevant under real operating conditions.

The selection of the substrate for molten salt tower receivers is very linked to the suitable receiver coating, and thus several coating types have been developed within the RAISELIFE project:

- ceramic paint consisting of a primer and absorbing layer (referred as BSII or Coating A),
- protective slurry aluminide coating protecting the steel substrate (INTA or Coating B) in combination with coating A on top,
- solar selective magnetron-sputtered coating applied on a polished substrate (Fraunhofer or Coating C), and
- power pack cementation multi-metallic diffusion coating based on chromium and manganese (Dechema or Coating D).

When applying coatings to metallic components, any degradation on the mechanical properties during the lifetime of the component should be observed. For this application, several metallic substrates might be considered based on costs, performance under corrosive conditions and high mechanical properties. Ferritic-martensitic grades might be selected due to its low costs, in comparison to Ni-based alloys and their relative high oxidation resistance and good mechanical properties at the given operation temperatures. The main alternative is the use of Ni-based alloys which provide excellent mechanical and corrosion properties, in spite of their higher costs.

The selection of a material system, i.e. substrate and coating, must be first evaluated based on accelerated tests in order to provide enough data prior considering the system as potential candidate for such application. The recommended list of tests that should be considered is listed below:

**Aging under high solar flux**
- Solar Cycling Tests at high flux, with fast heating and cooling rate
- Solar Cycling Tests at 250 kW/m², with slow heating and cooling rate

**Tests in climate chambers with environmental parameters**
- Condensation
- Damp heat
- Humidity freeze
- Natural salt spray

**Tests in furnaces, at high temperature during long periods**

The optical properties of the coated substrates should be measured before any aging procedure, at intermediate times and at the end of the corresponding aging test. More details on these tests can be found in the following documents, D3.1 “Accelerated aging testing and optical performance of four types of HSA coatings” and D6.9 “Best practice on accelerated aging”. Based on some of the above mentioned tests, some examples will be used to help on materials and coating selection.

Figure shows the good behavior of all the applied coating after solar cycling test. In case of the coating C (Fraunhofer) some corrosion was observed on the coating’s surface whereas in the case of coating D (Dechema) some delamination of the applied coating was observed.
When these coating are exposed to the damp heat test (Figure ) for 1,000h, the investigated coated T22 samples show a good behavior, to exception of coating C which developed several corrosion spots on its surface.

**Figure 6.1: Macro pictures of coated T22 steel samples (T22 - Gen1) before and after combined solar cycling.**

**Figure 6.2: T22 samples before and after 1000h of damp heat testing (IEC62108, Test 10.7b)**
Better behavior was observed when these coatings were applied to IN617 as substrate (Figure ). Any indication of degradation was observed after 1,000h testing.

As these types of tests may concern, the selected coatings exhibit a good behavior. However, when they are subjected to salt spray testing (Figure ), they experience a catastrophic behavior after 480h testing. In conclusion, for a material system (substrate + coating) to be considered as candidate material for this application, a larger number of tests have to be performed and properly evaluated.

Another critical test for material’s selection is the cyclic oxidation. These tests were performed on several substrates with various coating types in order to accelerate the coating failure. Some examples from this test are illustrated in Figure. At the beginning of the test, and after each 50 cycles, absorptance and emittance were measured. However, after the first 100 cycles no coating failure was observed. More severe conditions were applied to the testing samples by combing cycling with a certain humidity level according to the standard DIN ISO 6270. Note that at 100 cycles and later there are two measurements
(sometimes equal) which correspond to before (empty markers in Figure 6.5.b) and after (full markers in Figure .a) the corresponding 100 h of exposure to humidity. Again, no significant changes could be observed for the coatings in terms of absorptance or emittance. However, a close look on the surface of the coated samples reveals a severe damage of the coating when exposed to cyclic conditions and humidity.

![Figure 6.5](image)

*Figure 6.5: Adsorptance and emittance of coated and uncoated T22 after 200 cycles at 570°C, including 100h humidity exposure after 100 cycles and every 50 cycles. (Empty symbols correspond to the measurement before and full symbols to after exposure to humidity).*

However, Fraunhofer, DFI 1 and DDFI 2 coatings as well as the uncoated T22 coupon failed after just 100 cycles and 100 h of humidity, exhibiting corrosion pits on the coating and material’s surface. The values of absorptance and emittance were not affected. The BSII and INTA coatings have not yet failed after 200 cycles and a total of 300 h of humidity.

![Figure 6.6](image)

*Figure 6.6: Overview of the coating surface after cyclic oxidation test combined with humidity at 570°C.*
Once reviewing the results of the proposed tests, it can be concluded that steel containing low Chromium, such as T22 are not suitable for this application due to its severe corrosion. Better behavior was observed for other materials, e.g. T91, VM12-SCH and IN617 might be considered as potential candidate substrates. Another interesting alternative to IN617 is Hayne 230 (UNS N06230). This alloy (Ni-22%Cr-14%W-2Mo) combines high mechanical properties and high corrosion resistance, and for this dedicated application it might just need a single coating layer but not a primer coating.

However, the failure of the absorber coating based on the selected tests might be, to some extent, considered as “acceptable” and a “good enough”-concept can be selected for the final application, as local re-coating of the damaged areas on a panel section is still feasible (also from the economic point of view).

Other thermo-mechanical properties, such as creep rupture, fatigue, etc, are dominant criteria, as mechanical failure under thermal stress is much more critical for the plant operation (shutdown) as well severe corrosion through molten salts than the coating malfunction, because fitness for services can be applied in-service equipments in order to determine its continued operation based on defined flaws limits and allowances well defined by best practices criteria.

### 3.3. Economical assessment of degradation of steel tubes

The degradation of steel tubes does not really have a significant effect on the system performance, and thus the used steel tubes have to fulfill the requirements in terms of mechanical performance over the entire lifetime of the plant. It is not economically feasible the replacement of the tubing system within the designed lifetime of the plant. One activity running is to assess the impact of changing the heat capacity of the molten salt and its impact on the steel’s behavior. An update of this chapter will be provided when these results are available.
4. Case Studies

4.1. Case 1: Wrong selection of metallic material and coating for receiver components

Conditions

Isothermal exposure of the T22 material. Absorptance was measured at regular intervals for each testing temperature and the emittance was measured at the beginning and at the longest exposure time.

Material of construction

Coated and uncoated specimens of T22 steel (UNS K21590).

Exposure conditions

Isothermal oxidation tests were performed on all coated T22 at 530°C, 550°C and 570°C. Absorptance was measured after 100 h, 500 h, 1000 h and 2,000 h at each temperature, whereas emittance was measured at time zero and after 2,000 h exposure.

Examination and results

The absorptance values of coated and uncoated T22 after 2,000 h at 570°C are shown in Figure. No significant changes on the absorptance of the coated specimens but the uncoated T22 specimens corroded badly at all tested temperatures. Figure shows the sample’s surfaces tested at 570°C comparing the uncoated and coated specimens.

![Figure 6.7: a) Absorptance and b) reflectance of coated and uncoated T22 specimens after of 2000 h isothermal oxidation at 570°C.](image)
**Cause of failure and its explanation**

No significant changes on the absorptance of most of the coated specimens could be seen with the exception of the DFI coatings which showed a slight increase. The coating C (Fraunhofer) as well as the uncoated T22 showed high corrosion rates at all tested temperatures after rather short exposure time. The emittance values are not stable over the testing period.

**Solutions and recommendations**

Even though the substrate was not properly selected for such application due to its very high oxidation rate upon the prevailing testing conditions, the adequate selection and application of protective coatings might results in good system’s behavior, leading to insignificant changes in absorptance and emittance. Consequently, it would be recommended to use steels/alloys with improved corrosion resistance.

### 4.2. Case 2: Use of coatings for metallic receiver materials

**Conditions**

Exposure of coated substrates to standard grade solar salt (60wt% NaNO₃ - 40wt% KNO₃), containing an impurity level of 131 ppm chloride (NaCl) and 60 ppm sulphate (Na₂SO₄).

**Material of construction**

Tubes (flat ground samples) of UNS K90901 or T91 (9% Cr) and VM12-SHC, ASME Code Case 2781 (12% Cr).

**Exposure conditions**

Up to 10,000 h exposure in standard molten salt at 580°C.

**Examination and results**

After exposure of T91 steel (Figure ) severe corrosion was found in form of a non-protective iron-rich oxide scale with a thickness of approximately 200 µm very prone to suffer repeated spallation of the oxide scale. In addition, nitridation of the substrate might occur, which might have a strong impact on
the mechanical properties of the material and thus on its lifetime under the prevailing exposure conditions. The estimated corrosion rate was 169 µm/year for T91 and 60 µm/year for VM12-SHC.

Figure 6.9: a) Uncoated T91 after 10,000 h exposure in standard molten salts (impurity level: 131 ppm chloride and 60 ppm sulphate) under static conditions at 580°C and b) VM12-SHC exposed in molten salts under static conditions at 580°C.

Cause of failure and its explanation

Decomposition reactions might alter the molten salt composition by changing the nitrate/nitrite ratio and therefore its thermo-physical properties and as result, the concentration of oxidizing compounds/elements is significantly increased. In addition, considering the molten salt as an ionic electrolyte, the oxidizing elements can easily react with the metallic surfaces, while metal cations diffusing toward the metal surface can be dissolved into the salt melt. This is for instance, the case of Chromium, when present as Cr-rich oxide tends to form chromates or dichromates that can be dissolved in the molten salt and subsequently the consumption of the Cr present in the alloy is significantly increased, and thus larger depletion zones are formed and consequently, reducing the availability of the material to form a protective oxide scale layer.

Solutions and recommendations

The use of protective coatings or the use of high alloyed steels such as Ni-based alloys (e.g. Haynes 230). The use of e.g. slurry coatings (see Figure 13) provides sufficient protection to the substrate under the testing conditions. The gravimetric data shown in Figure 136.10.a illustrates the beneficial effect of using such coatings, where no deterioration was observed after 10,000 h exposure under static conditions at 580°C.
4.3. Case 3: Corrosion of substrates and protective coatings under high impurity level molten salts

Conditions
Exposure of coated and uncoated substrates to two solar salts (60wt% NaNO$_3$ - 40wt% KNO$_3$) containing two different impurity levels.

Material of construction
Tubes (samples) of UNS K90901 or T91 (9% Cr) and VM12-SHC (12% Cr), ASME Code Case 2781.

Exposure conditions
Up to 1,000 h exposure in molten salts at 560°C. Standard salt impurity level: 131 ppm chloride (NaCl) and 60 ppm sulphate (Na$_2$SO$_4$); increased impurity level: 500 ppm for both species by adding corresponding values of NaCl and Na$_2$SO$_4$.

Examination and results
The uncoated T91 and VM12-SHC specimens showed in both salt mixtures a weight gain over time (Figure 4.3.4). However, depending on the selected coating different behavior can be observed. DFI-coated T91 experienced a mass loss within the early stages of exposure due to the dissolution of the chromium carbide outer layer, but thereafter maintained a stable behavior. In the case of the INTA 1-coated T91 specimens a significantly high corrosion resistance was observed, exhibiting a very stable behavior in both salt mixtures.
Spallation events cannot be observed through net specific weight change kinetics. Therefore cross-sectional investigation was performed in order to rank the scaling behavior of coated and uncoated specimens in molten nitrate salt. Figure illustrates the SEM cross sectional images of uncoated T91 and VM12-SHC substrates immersed in the standard grade solar salt (impurity level: 131 ppm chloride and 60 ppm sulphate). The oxide scale grown on T91 had a maximum thickness of 10µm and showed a layered morphology consisting of an outer hematite layer and an inner Fe-Cr spinel layer. The oxide scale grown on VM12-SHC also showed a duplex morphology, which consisted of an outer hematite and inner Fe-Cr spinel layer. However, between the iron-rich nodules, a much thinner (< 1-2µm) scale was formed, which is associated with the initial Cr-rich scale formed of the substrate.
DFI 2 coated T91 showed a mass loss within the early stages of exposure, which is then followed by parabolic mass increase indicating protective behavior. The mass loss was associated with the dissolution of the pristine carbide layer. This can be verified from the cross sectional micrographs and the elemental distribution maps of the specimen after 1,000 h (Figure 6.13 Error! Reference source not found.), which show the absence of the initial formed carbide layer on top of the coating surface. The oxide scale had a similar duplex structure as the ones formed on the uncoated substrates and was characterized by an outer hematite and an inner Fe-Cr spinel layer. Notwithstanding the initial mass loss, the chromium enriched zone underneath the oxide scale can serve as a Cr-reservoir for the re-healing of the oxide scale. Therefore, sustainment of this protective behavior is expected for prolonged exposure durations despite the initial mass loss.
Solutions and recommendations
An increase on the impurity level of the corrosion media, might lead to an increase of its corrosiveness. Therefore, similar approaches as for the Case Study 2 shall be considered in both substrate and coating selection.

4.4. Case 4: Effect of the as-delivered inner surface of the tubular components

Conditions
Exposure of coated substrates to standard grade solar salt (60wt% NaNO₃ - 40wt% KNO₃), containing an impurity level of 131 ppm chloride (NaCl) and 60 ppm sulphate (Na₂SO₄).

Material of construction
Tubes (samples) of UNS K90901 or T91 (9% Cr) and VM12-SHC (12% Cr), ASME Code Case 2781.

Exposure conditions
Up to 2,000 h exposure in molten salts at 580°C. Two different surface aspects, ground surface (1200 SiC grit paper) and original as-delivered surface condition.

Examination and results
After 1,000h exposure, T91 ground specimen forms a rather compact oxide scale with a thickness of approximately 24 µm (Figure ). After longer exposure times, the scale forms a laminated structure and thus prone to suffer spallation. The as-delivered inner tube surface specimens form, under the same conditions, a much thicker oxide after both exposure times.
Similar results can be observed for VM12-SHC steel (Figure ), when these specimens with a ground surface treatment, the oxide scales formed are thin and very compact. After 2,000 h exposure a slightly increase in the scale thickness is observed. However, the VM12-SHC specimens with the as-delivered surface condition are exposed to molten salts, delaminated oxide scales are form, which are apparently detached from the sample's surface.
**Cause of failure and its explanation.**

Due to the low dew point during the different stages of heat treatment process of tube manufacturing, internal oxides of the more oxygen active elements (mainly Cr) are formed, which result in a depletion of these elements in the sub-scale region. As consequence, fast growing rates will be observed in comparison to ground specimens, where the mentioned internal oxidation zone is not present.

**Solutions and recommendations**

In order to undesired corrosion rates higher than expected based on published or owned data, it is suggested to proceed with an internal cleaning of the inner side of the tubes and associated pipework prior commissioning. There are several guidelines and regulations that can be used, such as VGB R-513e, in order to obtain clean inner surface by removing the initial as-delivered surface.